ENI SPA
Form 20-F
April 10, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 20-F

(Mark One)

REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) or (g) OF THE SECURITIES EXCHANGE ACT OF 1934

OR

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2013

OR

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

OR

SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Date of event requiring this shell company report

Commission file number: 1-14090

Eni SpA

(Exact name of Registrant as specified in its charter)

Republic of Italy

(Jurisdiction of incorporation or organization)

1, piazzale Enrico Mattei - 00144 Roma - Italy

(Address of principal executive offices)

Massimo Mondazzi
Eni SpA
1, piazza Ezio Vanoni
20097 San Donato Milanese (Milano) - Italy
Tel +39 02 52041730 - Fax +39 02 52041765
(Name, Telephone, Email and/or Facsimile number and Address of Company Contact Person)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	Name of each exchange on which registered
Shares	**New York Stock Exchange***
American Depositary Shares (Which represent the right to receive two Shares)	**New York Stock Exchange**

* Not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission.

Securities registered or to be registered pursuant to Section 12(g) of the Act:
None
Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
None

Indicate the number of outstanding shares of each of the issuer s classes of capital or common stock as of the close of the period covered by the annual report.

Ordinary shares of euro 1.00 each	**4,005,358,876**

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

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.
Yes No

Note - Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

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

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

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

Indicate by check mark if the registrant is a large accelerated filer, an accelerated filer, or a non accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer Accelerated filer Non-accelerated filer

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:
U.S. GAAP International Financial Reporting Standards as issued by the International Accounting Standards Board Other

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.
Item 17 Item 18

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes No

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Certain disclosures contained herein including, without limitation, information appearing in "Item 4 Information on the Company", and in particular "Item 4 Exploration & Production", "Item 5 Operating and Financial Review and Prospects" and "Item 11 Quantitative and Qualitative Disclosures about Market Risk" contain forward-looking statements regarding future events and the future results of Eni that are based on current expectations, estimates, forecasts, and projections about the industries in which Eni operates and the beliefs and assumptions of the management of Eni. Eni may also make forward-looking statements in other written materials, including other documents filed with or furnished to the U.S. Securities and Exchange Commission (the "SEC"). In addition, Eni s senior management may make forward-looking statements orally to analysts, investors, representatives of the media and others. In particular, among other statements, certain statements with regard to management objectives, trends in results of operations, margins, costs, return on capital, risk management and competition are forward looking in nature. Words such as expects , anticipates , targets , goals , projects , intends , plans , believes , seeks , estimates , variations of such words, and similar expressions are intended to identify such forward-looking statements. These forward-looking statements are only predictions and are subject to risks, uncertainties, and assumptions that are difficult to predict because they relate to events and depend on circumstances that will occur in the future. Therefore, Eni s actual results may differ materially and adversely from those expressed or implied in any forward-looking statements. Factors that might cause or contribute to such differences include, but are not limited to, those discussed in this Annual Report on Form 20-F under the section entitled "Risk factors" and elsewhere. Any forward-looking statements made by or on behalf of Eni speak only as of the date they are made. Eni does not undertake to update forward-looking statements to reflect any changes in Eni s expectations with regard thereto or any changes in events, conditions or circumstances on which any such statement is based. The reader should, however, consult any further disclosures Eni may make in documents it files with the SEC.

CERTAIN DEFINED TERMS

In this Form 20-F, the terms "Eni", the "Group", or the "Company" refer to the parent company Eni SpA and its consolidated subsidiaries and, unless the context otherwise requires, their respective predecessor companies.
All references to "Italy" or the "State" are references to the Republic of Italy, all references to the "Government" are references to the government of the Republic of Italy. For definitions of certain oil and gas terms used herein and certain conversions, see "Glossary" and "Conversion Table".

PRESENTATION OF FINANCIAL AND OTHER INFORMATION

The Consolidated Financial Statements of Eni, included in this Annual Report, have been prepared in accordance with IFRS issued by the International Accounting Standards Board (IASB).

Unless otherwise indicated, any reference herein to "Consolidated Financial Statements" is to the Consolidated Financial Statements of Eni (including the Notes thereto) included herein.

Unless otherwise specified or the context otherwise requires, references herein to "dollars", "$", "U.S. dollars" and "US$" are to the currency of the United States, and references to "euro" and " " are to the currency of the European Monetary Union.

Unless otherwise specified or the context otherwise requires, references herein to "Division" and "segment" are to Eni s business activities: Exploration & Production, Gas & Power, Refining & Marketing, Engineering & Construction, Chemicals and Other activities.

References to Versalis or Chemicals are to Eni s chemical activities engaged through its fully-owned subsidiary Versalis and Versalis controlled entities.

STATEMENTS REGARDING COMPETITIVE POSITION

Statements made in "Item 4 Information on the Company" referring to Eni s competitive position are based on the Company s belief, and in some cases rely on a range of sources, including investment analysts reports, independent market studies and Eni s internal assessment of market share based on publicly available information about the financial results and performance of market participants. Market share estimates contained in this document are based on management estimates unless otherwise indicated.

GLOSSARY

A glossary of oil and gas terms is available on Eni s web page at the address eni.com. Below is a selection of the most frequently used terms.

Financial terms

Leverage	A non-GAAP measure of the Company s financial condition, calculated as the ratio between net borrowings and shareholders equity, including minority interest. For a discussion of management s view of the usefulness of this measure and its reconciliation with the most directly comparable GAAP measure which in the case of the Company refers to IFRS, see "Item 5 Financial Condition".
Net borrowings	Eni evaluates its financial condition by reference to "net borrowings", which is a non-GAAP measure. Eni calculates net borrowings as total finance debt less: cash, cash equivalents and certain very liquid investments not related to operations, including among others non-operating financing receivables and securities not related to operations. Non-operating financing receivables consist of amounts due to Eni s financing subsidiaries from banks and other financing institutions and amounts due to other subsidiaries from banks for investing purposes and deposits in escrow. Securities not related to operations consist primarily of government and corporate securities. For a discussion of management s view of the usefulness of this measure and its reconciliation with the most directly comparable GAAP measure which in the case of the Company refers to IFRS, see "Item 5 Financial condition".
TSR (Total Shareholder Return)	Management uses this measure to asses the total return of the Eni's shares. It is calculated on a yearly basis, keeping account of changes in prices (beginning and end of year) and dividends distributed and reinvested at the ex-dividend date.

Business terms

AEEG (Authority for Electricity and Gas)	The Regulatory Authority for Electricity and Gas is the Italian independent body which regulates, controls and monitors the electricity and gas sectors and markets in Italy. The Authority s role and purpose is to protect the interests of users and consumers, promote competition and ensure efficient, cost-effective and profitable nationwide services with satisfactory quality levels.
Associated gas	Associated gas is a natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as Gas-Cap Gas or Solution Gas.
Average reserve life index	Ratio between the amount of reserves at the end of the year and total production for the year.
Barrel/BBL	Volume unit corresponding to 159 liters. A barrel of oil corresponds to about 0.137 metric tons.
BOE	Barrel of Oil Equivalent. It is used as a standard unit measure for oil and natural gas. The latter is converted from standard cubic meters into barrels of oil equivalent using a certain coefficient (see "Conversion Table").

Concession contracts	Contracts currently applied mainly in Western countries regulating relationships between states and oil companies with regards to hydrocarbon exploration and production. The company holding the mining concession has an exclusive on exploration, development and production activities and for this reason it acquires a right to hydrocarbons extracted against the payment of royalties on production and taxes on oil revenues to the state.
Condensates	Condensates is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.
Consob	The National Commission for listed companies and the stock exchange of Italy.
Contingent resources	Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies.
Conversion capacity	Maximum amount of feedstock that can be processed in certain dedicated facilities of a refinery to obtain finished products. Conversion facilities include catalytic crackers, hydrocrackers, visbreaking units, and coking units.

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Conversion index	Ratio of capacity of conversion facilities to primary distillation capacity. The higher the ratio, the higher is the capacity of a refinery to obtain high value products from the heavy residue of primary distillation.
Deep waters	Waters deeper than 200 meters.
Development	Drilling and other post-exploration activities aimed at the production of oil and gas.
Enhanced recovery	Techniques used to increase or stretch over time the production of wells.
EPC	Engineering, Procurement and Construction.
EPCI	Engineering, Procurement, Construction and Installation.
Exploration	Oil and natural gas exploration that includes land surveys, geological and geophysical studies, seismic data gathering and analysis and well drilling.
FPSO	Floating Production Storage and Offloading System.
FSO	Floating Storage and Offloading System.
Infilling wells	Infilling wells are wells drilled in a producing area in order to improve the recovery of hydrocarbons from the field and to maintain and/or increase production levels.
LNG	Liquefied Natural Gas obtained through the cooling of natural gas to minus 160 °C at normal pressure. The gas is liquefied to allow transportation from the place of extraction to the sites at which it is transformed back into its natural gaseous state and consumed. One tonne of LNG corresponds to 1,400 cubic meters of gas.
LPG	Liquefied Petroleum Gas, a mix of light petroleum fractions, gaseous at normal pressure and easily liquefied at room temperature through limited compression.
Margin	The difference between the average selling price and direct acquisition cost of a finished product or raw material excluding other production costs (e.g. refining margin, margin on distribution of natural gas and petroleum products or margin of petrochemical products). Margin trends reflect the trading environment and are, to a certain extent, a gauge of industry profitability.
Mineral Potential	(Potentially recoverable hydrocarbon volumes) Estimated recoverable volumes which cannot be defined as reserves due to a number of reasons, such as the temporary lack of viable markets, a possible commercial recovery dependent on the development of new technologies, or for their location in accumulations yet to be developed or where evaluation of known accumulations is still at an early stage.
Mineral Storage	According to Legislative Decree No. 164/2000, these are volumes required for allowing optimal operation of natural gas fields in Italy for technical and economic reasons. The purpose is to ensure production flexibility as required by long-term purchase contracts as well as to cover technical risks associated with production.

Modulation Storage	According to Legislative Decree No. 164/2000, these are volumes required for meeting hourly, daily and seasonal swings in demand.
Natural gas liquids (NGL)	Liquid or liquefied hydrocarbons recovered from natural gas through separation equipment or natural gas treatment plants. Propane, normal-butane and isobutane, isopentane and pentane plus, that were previously defined as natural gasoline, are natural gas liquids.
Network Code	A code containing norms and regulations for access to, management and operation of natural gas pipelines.
Over/Under lifting	Agreements stipulated between partners which regulate the right of each to its share in the production for a set period of time. Amounts lifted by a partner different from the agreed amounts determine temporary Over/Under lifting situations.
Possible reserves	Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.
Probable reserves	Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.
Primary balanced refining capacity	Maximum amount of feedstock that can be processed in a refinery to obtain finished products measured in BBL/d.
Production Sharing Agreement (PSA)	Contract in use in African, Middle Eastern, Far Eastern and Latin American countries, among others, regulating relationships between states and oil companies with regard to the exploration and production of hydrocarbons. The mineral right is awarded to the national oil company jointly with the foreign oil company that has an exclusive right to

perform exploration, development and production activities and can enter into agreements with other local or international entities. In this type of contract the national oil company assigns to the international contractor the task of performing exploration and production with the contractor s equipment and financial resources. Exploration risks are borne by the contractor and production is divided into two portions: "cost oil" is used to recover costs borne by the contractor and "profit oil" is divided between the contractor and the national company according to variable schemes and represents the profit deriving from exploration and production. Further terms and conditions of these contracts may vary from country to country.

Proved reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. Reserves are classified as either developed and undeveloped. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Reserves

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Reserve life index

Ratio between the amount of proved reserves at the end of the year and total production for the year.

Reserve replacement ratio

Measure of the reserves produced replaced by proved reserves. Indicates the company s ability to add new reserves through exploration and purchase of property. A rate higher than 100% indicates that more reserves were added than produced in

	the period. The ratio should be averaged on a three-year period in order to reduce the distortion deriving from the purchase of proved property, the revision of previous estimates, enhanced recovery, improvement in recovery rates and changes in the amount of reserves in PSAs due to changes in international oil prices.
Ship-or-pay	Clause included in natural gas transportation contracts according to which the customer is requested to pay for the transportation of gas whether or not the gas is actually transported.
Strategic Storage	According to Legislative Decree No. 164/2000, these are volumes required for covering lack or reduction of supplies from extra-European sources or crises in the natural gas system.
Take-or-pay	Clause included in natural gas supply contracts according to which the purchaser is bound to pay the contractual price or a fraction of such price for a minimum quantity of gas set in the contract whether or not the gas is collected by the purchaser. The purchaser has the option of collecting the gas paid for and not delivered at a price equal to the residual fraction of the price set in the contract in subsequent contract years.
Upstream/Downstream	The term upstream refers to all hydrocarbon exploration and production activities. The term downstream includes all activities inherent to the oil and gas sector that are downstream of exploration and production activities.

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ABBREVIATIONS

mmCF	=	million cubic feet	ktonnes	=	thousand tonnes
BCF	=	billion cubic feet	mmtonnes	=	million tonnes
mmCM	=	million cubic meters	MW	=	megawatt
BCM	=	billion cubic meters	GWh	=	gigawatthour
BOE	=	barrel of oil equivalent	TWh	=	terawatthour
KBOE	=	thousand barrel of oil equivalent	/d	=	per day
mmBOE	=	million barrel of oil equivalent	/y	=	per year
BBOE	=	billion barrel of oil equivalent	E&P	=	the Exploration & Production segment
BBL	=	barrels	G&P	=	the Gas & Power segment
KBBL	=	thousand barrels	R&M	=	the Refining & Marketing segment
mmBBL	=	million barrels	E&C	=	the Engineering & Construction segment
BBBL	=	billion barrels			

CONVERSION TABLE

1 acre	= 0.405 hectares	
1 barrel	= 42 U.S. gallons	
1 BOE	= 1 barrel of crude oil	= 5,492 cubic feet of natural gas
1 barrel of crude oil per day	= approximately 50 tonnes of crude oil per year	
1 cubic meter of natural gas	= 35.3147 cubic feet of natural gas	
1 cubic meter of natural gas	= approximately 0.00643 barrels of oil equivalent	
1 kilometer	= approximately 0.62 miles	
1 short ton	= 0.907 tonnes	= 2,000 pounds
1 long ton	= 1.016 tonnes	= 2,240 pounds
1 tonne	= 1 metric ton	= 1,000 kilograms = approximately 2,205 pounds
1 tonne of crude oil	= 1 metric ton of crude oil	=

approximately 7.3 barrels of crude oil (assuming an API gravity of 34 degrees)

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PART I

Item 1. IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISORS

NOT APPLICABLE

Item 2. OFFER STATISTICS AND EXPECTED TIMETABLE

NOT APPLICABLE

Item 3. KEY INFORMATION

Selected Financial Information

The Consolidated Financial Statements of Eni have been prepared in accordance with International Financial Reporting Standards (IFRS) issued by the International Accounting Standards Board (IASB). The tables below present Eni selected historical financial data prepared in accordance with IFRS as of and for the years ended December 31, 2009, 2010, 2011, 2012 and 2013. Financial information for 2012 has been restated to reflect the adoption of amendments to IAS 19 Employee Benefits and the adoption of IFRS 10 Consolidated Financial Statements and IFRS 11 Joint Arrangements . Prior year data have not been restated. For further information see Item 18 note 4 Financial statements and changes in accounting policies of the Notes to the Consolidated Financial Statements .

The selected historical financial data presented herein are derived from Eni s Consolidated Financial Statements included in Item 18.

All such data should be read in connection with the Consolidated Financial Statements and the related notes thereto included in Item 18.

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	Year ended December 31,				
	2009	2010	2011	2012	2013
	(euro million except data per share and per ADR)				
CONSOLIDATED PROFIT STATEMENT DATA					
Net sales from continuing operations	81,932	96,617	107,690	127,109	114,697
Operating profit by segment from continuing operations					
Exploration & Production	9,120	13,866	15,887	18,470	14,868
Gas & Power	1,914	896	(326)	(3,125)	(2,967)
Refining & Marketing	(102)	149	(273)	(1,264)	(1,492)
Chemicals	(675)	(86)	(424)	(681)	(725)
Engineering & Construction	881	1,302	1,422	1,453	(98)
Other activities	(436)	(1,384)	(427)	(300)	(337)
Corporate and financial companies	(420)	(361)	(319)	(341)	(399)
Impact of unrealized intragroup profit elimination and other consolidation adjustments (1)	1,513	1,100	1,263	996	38
Operating profit from continuing operations	11,795	15,482	16,803	15,208	8,888
Net profit attributable to Eni from continuing operations	4,488	6,252	6,902	4,200	5,160
Net profit (loss) attributable to Eni from discontinued operations	(121)	66	(42)	3,590	
Net profit attributable to Eni	4,367	6,318	6,860	7,790	5,160
Data per ordinary share (euro) (2)					
Operating profit:					
- basic	3.26	4.27	4.64	4.20	2.45
- diluted	3.26	4.27	4.64	4.20	2.45
Net profit attributable to Eni basic and diluted from continuing operations	1.24	1.72	1.90	1.16	1.42
Net profit attributable to Eni basic and diluted from discontinued operations	(0.03)	0.02	(0.01)	0.99	
Net profit attributable to Eni basic and diluted	1.21	1.74	1.89	2.15	1.42
Data per ADR ($) (2) (3)					
Operating profit:					
- basic	9.08	11.33	12.92	10.79	6.51
- diluted	9.08	11.33	12.92	10.79	6.51
Net profit attributable to Eni basic and diluted from continuing operations	3.45	4.56	5.32	2.98	3.77
Net profit attributable to Eni basic and diluted from discontinued operations	(0.08)	0.05	(0.03)	2.54	
Net profit attributable to Eni basic and diluted	3.36	4.62	5.26	5.53	3.77

(1) This item pertains to intragroup sales of commodities and capital goods recorded in the assets of the purchasing business segment as of the end of the reporting period.

(2) Euro per share or U.S. dollars per American Depositary Receipt (ADR), as the case may be. One ADR represents two Eni shares. The dividend amount for 2013 is based on the proposal of Eni s management which is submitted to approval at the Annual General Shareholders Meeting scheduled on May 8, 2014.

(3) Eni s Financial Statements are stated in euro. The translations of certain euro amounts into U.S. dollars are included solely for the convenience of the reader. The convenient translations should not be construed as representations that the amounts in euro have been, could have been, or could in the future be, converted into U.S. dollars at this or any other rate of exchange. Data per ADR, with the exception of dividends, were translated at the EUR/US$ average exchange rate as recorded by in the Federal Reserve Board official statistics for each year presented (see the table on page 5). Dividends per ADR for the years 2009 through 2012 were translated into U.S. dollars for each year presented using the Noon Buying Rate on payment dates, as recorded on the payment date of the interim dividend and of the balance to the full-year dividend, respectively.
The dividend for 2013 based on the management s proposal to the General Shareholders Meeting and subject to approval was translated as per the portion related to the interim dividend (euro 1.10 per ADR) at the Noon Buying Rate recorded on the payment date on September 23, 2013, while the balance of euro 1.10 per ADR was translated at the Noon Buying Rate as recorded on December 31, 2013. The balance dividend for 2013 once the full-year dividend is approved by the Annual General Shareholders Meeting is payable on May 22, 2014 to holders of Eni shares, being the ex-dividend date May 19, while ADRs holders will be paid on June 6, 2014.

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	As of December 31,				
	2009	**2010**	**2011**	**2012**	**2013**
	(euro million except data per share and per ADR)				
CONSOLIDATED BALANCE SHEET DATA					
Total assets	117,529	131,860	142,945	140,192	138,341
Short-term and long-term debt	24,800	27,783	29,597	24,192	25,560
Capital stock issued	4,005	4,005	4,005	4,005	4,005
Minority interest	3,978	4,522	4,921	3,357	2,839
Shareholders equity - Eni share	46,073	51,206	55,472	59,060	58,210
Capital expenditures from continuing operations	12,216	12,450	11,909	12,805	12,800
Weighted average number of ordinary shares outstanding (fully diluted - shares million)	3,622	3,622	3,623	3,623	3,623
Dividend per share (euro) [1]	1.00	1.00	1.04	1.08	1.10
Dividend per ADR ($) [1] [2]	2.91	2.64	2.73	2.82	3.00

(1) Euro per share or U.S. dollars per American Depositary Receipt (ADR), as the case may be. One ADR represents two Eni shares. The dividend amount for 2013 is based on the proposal of Eni s management which is submitted to approval at the Annual General Shareholders Meeting scheduled on May 8, 2014.

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Selected Operating Information

The tables below set forth selected operating information with respect to Eni s proved reserves, developed and undeveloped, of crude oil (including condensates and natural gas liquids) and natural gas, as well as other data as of and for the years ended December 31, 2009, 2010, 2011, 2012 and 2013.

	Year ended December 31,				
	2009	2010	2011	2012	2013
Proved reserves of liquids of consolidated subsidiaries at period end (mmBBL)	3,377	3,415	3,134	3,084	3,079
of which developed	*2,001*	*1,951*	*1,850*	*1,762*	*1,831*
Proved reserves of liquids of equity-accounted entities at period end (mmBBL)	86	208	300	266	148
of which developed	*34*	*52*	*45*	*44*	*35*
Proved reserves of natural gas of consolidated subsidiaries at period end (BCF) (1)	16,262	16,198	15,582	14,190	14,442
of which developed	*11,650*	*10,965*	*10,363*	*8,965*	*8,542*
Proved reserves of natural gas of equity-accounted entities at period end (BCF)	1,588	1,684	4,700	6,767	3,726
of which developed	*234*	*246*	*53*	*424*	*34*
Proved reserves of hydrocarbons of consolidated subsidiaries at period end (mmBOE) (1)	6,209	6,332	5,940	5,667	5,708
of which developed	*4,030*	*3,926*	*3,716*	*3,394*	*3,387*
Proved reserves of hydrocarbons of equity-accounted entities at period end (mmBOE)	362	511	1,146	1,499	827
of which developed	*74*	*96*	*54*	*122*	*40*
Average daily production of liquids (KBBL/d) (2)	1,007	997	845	882	833
Average daily production of natural gas available for sale (mmCF/d) (2)	4,074	4,222	3,763	4,118	3,868
Average daily production of hydrocarbons available for sale (KBOE/d) (2)	1,716	1,757	1,523	1,631	1,537
Hydrocarbon production sold (mmBOE)	622.8	638.0	548.5	598.7	555.3
Oil and gas production costs per BOE (3)	7.41	8.89	10.86	10.82	12.19
Profit per barrel of oil equivalent (4)	8.14	11.91	16.98	15.95	15.46

(1) Includes approximately 769, 767 and 767 BCF of natural gas held in storage in Italy as of December 31, 2009, 2010 and 2011, respectively.

(2) Referred to Eni s subsidiaries and its equity-accounted entities. Natural gas production volumes exclude gas consumed in operations (300, 318, 321, 383 and 451 mmCF/d in 2009, 2010, 2011, 2012 and 2013, respectively).

(3) Expressed in U.S. dollars. Consists of production costs of consolidated subsidiaries (costs incurred to operate and maintain wells and field equipment including also royalties) prepared in accordance with IFRS divided by production on an available-for-sale basis, expressed in barrels of oil equivalent. See the unaudited supplemental oil and gas information in "Item 18 Notes to the Consolidated Financial Statements".

(4) Expressed in U.S. dollars. Results of operations from oil and gas producing activities of consolidated subsidiaries, divided by actual sold production, in each case prepared in accordance with IFRS to meet ongoing U.S. reporting obligations under Topic 932. See the unaudited supplemental oil and gas information in "Item 18 Notes to the Consolidated Financial Statements" for a calculation of results of operations from oil and gas producing activities.

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Selected Operating Information *continued*

	Year ended December 31,				
	2009	2010	2011	2012	2013
Sales of natural gas to third parties (1)	83.79	75.81	77.84	77.87	77.67
Natural gas consumed by Eni (1)	5.81	6.19	6.21	6.43	5.93
Sales of natural gas of affiliates (Eni s share) (1)	7.95	9.41	9.85	8.29	6.96
Total sales and own consumption of natural gas of the Gas & Power segment (1)	97.55	91.41	93.90	92.59	90.56
E&P natural gas sales in Europe and in the Gulf of Mexico (1)	6.17	5.65	2.86	2.73	2.61
Worldwide natural gas sales (1)	103.72	97.06	96.76	95.32	93.17
Electricity sold (2)	33.96	39.54	40.28	42.58	35.05
Refinery throughputs (3)	34.55	34.80	31.96	30.01	27.38
Balanced capacity of wholly-owned refineries (4)	554	564	574	574	574
Retail sales (in Italy and rest of Europe) (3)	12.02	11.73	11.37	10.87	9.69
Number of service stations at period end (in Italy and rest of Europe)	5,986	6,167	6,287	6,384	6,386
Average throughput per service station (in Italy and rest of Europe) (5)	2,477	2,353	2,206	2,064	1,828
Chemical production (3)	6.52	7.22	6.25	6.09	5.82
Engineering & Construction order backlog at period end (6)	18,730	20,505	20,417	19,739	17,514
Employees at period end (units) (7)	71,461	73,768	72,574	77,838	82,289

(1) Expressed in BCM.
(2) Expressed in TWh.
(3) Expressed in mmtonnes.
(4) Expressed in KBBL/d.
(5) Expressed in thousand liters per day.
(6) Expressed in euro million.
(7) Relating to continuing operations for all periods presented.

Exchange Rates

The following tables set forth, for the periods indicated, certain information regarding the Noon Buying Rate in U.S. dollars per euro, rounded to the second decimal (Source: The Federal Reserve Board).

	High	Low	Average (1)	At period end
	(U.S. dollars per euro)			
Year ended December 31,				
2009	1.51	1.25	1.39	1.44
2010	1.46	1.19	1.33	1.34
2011	1.49	1.29	1.39	1.29
2012	1.35	1.21	1.29	1.32
2013	1.38	1.28	1.33	1.38

(1) Average of the Noon Buying Rates for the last business day of each month in the period.

	High	Low	At period end
	(U.S. dollars per euro)		
October 2013	1.38	1.35	1.36
November 2013	1.36	1.34	1.36
December 2013	1.38	1.35	1.38
January 2014	1.37	1.35	1.35
February 2014	1.38	1.35	1.38
March 2014	1.39	1.37	1.38

Fluctuations in the exchange rate between the euro and the dollar affect the dollar equivalent of the euro price of the Shares on the Telematico and the dollar price of the ADRs on the New York Stock Exchange (NYSE). Exchange rate fluctuations also affect the dollar amounts received by owners of ADRs upon conversion by the Depository of cash dividends paid in euro on the underlying Shares. The Noon Buying Rate on April 4, 2014 was $1.3704 per euro 1.00.

Risk factors

Competition

There is strong competition worldwide, both within the oil industry and with other industries, to supply energy to the industrial, commercial and residential energy markets

Eni faces strong competition in each of its business segments.

In the current uncertain financial and economic environment, Eni expects that prices of energy commodities, in particular oil and gas, will be very volatile, with average prices and margins influenced by changes in the global supply and demand for energy as well as in the market dynamics. This is likely to increase competition in all of Eni s businesses, which may impact costs and margins.

In the Exploration & Production segment Eni faces competition from both international oil companies and state-owned oil companies for obtaining exploration and development rights, and developing and applying new technologies to maximize hydrocarbon recovery. Furthermore, Eni may face a competitive disadvantage because of its relatively smaller size compared to other international oil companies, particularly when bidding for large scale or capital intensive projects, and may be exposed to industry-wide cost increases to a greater extent compared to its larger competitors given its potentially smaller market power with respect to suppliers. If, as a result of those competitive pressures, Eni fails to obtain new exploration and development acreage, to apply and develop new technologies, and to control cost, its growth prospects and future results of operations and cash flows may be adversely affected.

In the Gas & Power segment, Eni faces strong competition from gas and energy players to sell gas and electricity to the industrial segment and the retail market both in Italy and across Europe. Competition has been fuelled by ongoing weak trends in demand due to the downturn and macroeconomic uncertainties, oversupplied markets and inter-fuel competition due to the rising use of coal in firing power plants and a growth in renewable sources of energy (such as photovoltaic and solar) which have materially impacted the use of gas in the production of electricity and consequently, gas sales to the thermoelectric industry. These market imbalances are owed to the fact that in past years, European operators committed to purchase large amounts of gas under long-term supply contracts, with take-or-pay clauses from the main producing countries bordering Europe (namely Russia and Algeria). These operators built large upgrades at existing pipelines and new infrastructures along several European routes to expand gas import capacity to the Continent. They did this based on certain long-term projections about gas demand growth. Due to the economic and financial crisis and inter-fuel competition, those projected increases in gas demand failed to materialize resulting in a situation of oversupply and pricing pressure. The "shale-gas revolution" in the United States was another fundamental trend that added to the oversupply condition in the European marketplace. The discovery and development of large deposits of shale gas in the United States have progressively reduced the country s dependence on LNG imports to zero. As a result of this, upstream producers were forced to redirect large LNG supplies to markets elsewhere in the world, including Europe. Large gas availability on the marketplace in Europe fuelled by take-or-pay contracts and worldwide LNG streams has driven the development of very liquid continental hubs to trade spot gas. Shortly spot prices at continental hubs have become the main benchmarks to which selling prices are indexed in supplies to large industrial customers and thermoelectric utilities. The profitability of gas operators was negatively impacted by falling sales prices at those hubs, where prices have been pressured by intense competition among gas operators in the face of weak demand, oversupplies and the constraint to dispose of minimum annual volumes of gas to be purchased under long-tem

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supply contracts. These negative trends were exacerbated by the fact that spot prices have ceased to track the oil prices to which Eni s long term supply contracts are linked, resulting in a decoupling between trends in prices and in costs. Due to those fundamental shifts in market dynamics and a current demand downturn, the Company s Gas & Power segment incurred operating losses in each of the latest three years (euro 2,967 million, euro 3,125 million and euro 326 million in 2013, 2012 and 2011, respectively). Our gas marketing business outlook will remain weak for the foreseeable future as management believes that the ongoing negative trends of poor demand, continuing competition and oversupply have become structural headwinds. These developments may adversely affect the Company s future results of operations and cash flows in its gas business, also taking into account the Company s contractual obligations to collect minimum annual volumes of gas (pursuant to its long-term gas supply contracts with take-or-pay clauses) and the Company s efforts to re-negotiate new pricing terms of such contracts, which better track market prices compared to the original oil-linked indexation. See the sector-specific risk section below. Eni is also facing competition from large, well-established European utilities and other international oil and gas companies in growing its market share and acquiring or retaining customers. A number of large customers, particularly electricity producers and large industrial buyers have entered the wholesale market of gas by directly purchasing gas from producers or sourcing it at the continental spot markets adding further pressures on the economics of gas operators, including Eni. Management believes that this trend will continue in the future. At the same time, a number of national gas producers belonging to countries with large gas reserves have started to sell natural gas directly to final customers, entering in direct competition with players like Eni which resell gas purchased from producing countries to final customers. These developments may increase the level of competition and reduce Eni s expected operating profit and cash flows in the gas business. Further, gas prices in the residential market have historically been established by independent, governmental authorities in Italy and elsewhere in Europe. The indexation mechanisms used by those authorities have generally tracked a basket of petroleum products, mirroring the oil-indexed purchase prices of gas resellers like Eni, thus enabling resellers to pass a large part of cost increases of the raw material on to final customers in the retail market. In recent years, the Italian Authority has introduced a number of adjustments to the oil linked formula to take into account the public goal of containing the impact of energy inflation on households and other public services (such as hospitals and schools). Finally, following enactment in Italy of a new regulatory regime which became effective October 1, 2013, management expects that the Company s selling margins in the residential segment are likely to come under pressure due to the implementation of a less favorable indexation mechanism of the raw material cost in supplies to such customers than in the past. This new mechanism establishes that the cost of the raw material be indexed to market benchmarks recorded at spot markets, and replaces the previous oil-linked mechanism which mirrored a basket of long-term supply contracts. The Company expects that similar measures will be introduced by other market regulators in European countries where Eni sells gas to residential customers (see sector-specific risk factors below). Management believes these developments will negatively impact future results of operations and cash flow. In its Gas & Power segment, Eni is vertically integrated in the production of electricity via its gas-fired power plants which currently use the combined-cycle technology. In the electricity business, Eni competes with other producers and traders from Italy or outside Italy who sell electricity in the Italian market. Going forward, the Company expects continuing competition due to the projections of weak economic growth in Italy and Europe over the foreseeable future, also causing outside players to place excess production on the Italian market. The economics of the gas-fired electricity business have dramatically changed over the latest few years due to ongoing competitive trends. Spot prices of electricity in the wholesale market across Europe have decreased due to excess supplies driven by the growing production of electricity from renewable sources, which also benefit from governmental subsides, and a recovery in the production of coal-fired electricity generation which has been helped by a substantial reduction in the price of this fuel on the back of a massive oversupply of coal which occurred on a global scale. As a result of falling electricity prices, margins on the production of gas-fired electricity went into negative territory. We believe that the profitability outlook in this business will remain weak in the foreseeable future. Due to the projections of negative future cash flows, Eni decided to recognize an impairment charge of its power plants in the amount of approximately euro 1 billion in the 2013 consolidated accounts.

In the retail marketing of refined products both in Italy and outside Italy, Eni competes with oil companies and non-oil operators (such as supermarket chains and other commercial operators) to obtain concessions to establish and operate service stations. Eni s service stations compete primarily on the basis of pricing, services and availability of non-petroleum products. In Italy, the latest administrative measures in this field have aimed to enhance the level of competition in the retail market of fuels, for example by easing the commercial ties between independent and other non-oil operators of service stations and oil companies, enlarging options to build and operate fully-automated service stations, and opening up the merchandising of various kinds of goods and services at service stations. These developments have boosted the level of competition in the marketplace adding further pressure on selling prices and reducing opportunities of increasing the market share in Italy. We expect that competitive pressures will continue in the foreseeable future due to anticipated weak trends in the domestic demand for fuels, oversupplies of refined products due to existing excess refining capacity in Europe and growing competition of products streams coming from Russia, the Middle East, East Asia and the United States. Finally, Eni s margins on refined products have been affected by production cost disadvantages due to unfavorable geographic location and lack of scale of

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Eni s refineries, and narrowing price differentials between the Brent benchmark and heavy crude qualities. This latter trend has reflected ongoing reduced supplies of heavy crudes in the Mediterranean Area, reversing the pattern observed historically whereby heavy crude qualities traded at a discount against the Brent benchmark due to their relatively smaller yield of valuable products. This negative trend has particularly hit Eni s profitability of complex cycles which depends on the availability of cheaper crude qualities than the Brent crude in order to remunerate the higher operating costs of complex plants. This segment reported losses at the operating level in each of the latest three years (euro 1,492 million, euro 1,264 million and euro 273 million in 2013, 2012 and 2011, respectively) driven by the structural headwinds in the industry described above. Based on those trends we believe that the profitability outlook in our Refining & Marketing segment will remain negative over the foreseeable future.

In the Chemical segment, Eni faces strong competition from well-established international players and state-owned petrochemical companies, particularly in the most commoditized market segments such as the production of basic petrochemical products and plastics. Many of those competitors based in the Far East and Middle East are able to benefit from cost advantages due to larger scale, looser environmental regulations, availability of cheaper feedstock, and more favorable location and proximity to end-markets. Excess capacity and sluggish economic growth may exacerbate competitive pressures. Furthermore, Eni expects that petrochemical producers based in the United States will regain market share in the future, leveraging on a competitive cost structure due to the increasing availability of cheap feedstock deriving from the production of domestic shale gas. The Company expects continuing margin pressures in the foreseeable future as a result of those trends. This segment reported operating losses in each of the latest three years (euro 725 million, euro 681 million and euro 424 million in 2013, 2012 and 2011, respectively) including significant amounts of asset impairment losses, driven by the structural headwinds in the industry described above.

Competition in the oilfield services, construction and engineering industries is primarily based on technical expertise, quality and number of services and availability of technologically advanced facilities (for example, vessels for offshore construction). Lower oil prices could result in lower margins and lower demand for oil services. In 2013, a soft demand environment, intense competition among oilfield service providers coupled with Company-specific issues at certain projects drove a substantial reversal in the profitability of Eni s Engineering & Construction business segment which reported an operating loss of euro 98 million for the full year 2013. The Company s failure or inability to respond effectively to competition could adversely impact the Company s growth prospects, future results of operations and cash flows.

Safety, security, environmental and other operational risks

The Group engages in the exploration and production of oil and natural gas, processing, transportation, and refining of crude oil, transport of natural gas, storage and distribution of petroleum products, production of base chemicals, plastics and elastomers. By their nature the Group s operations expose Eni to a wide range of significant health, safety, security and environmental risks. The magnitude of these risks is influenced by the geographic range, operational diversity and technical complexity of our activities. Eni s future results from operations and liquidity depend on its ability to identify and mitigate the risks and hazards inherent to operating in those industries.

In exploration and production, Eni faces natural hazards and other operational risks including those relating to the physical characteristics of oil and natural gas fields. These include the risks of eruptions of crude oil or of natural gas, discovery of hydrocarbon pockets with abnormal pressure, crumbling of well openings, leaks that can harm the environment and the security of our personnel and risks of blowout, fire or explosion. Accidents at a single well can lead to loss of life, damage or destruction to property, environmental damage and consequently potential economic losses that could have a material and adverse effect on the business, results of operation, liquidity, reputation and prospects of the Group.

Eni s activities in the Refining & Marketing and Chemical segments also entail health, safety and environmental risks related to the overall life cycle of the products manufactured, and to raw materials used in the manufacturing process, such as oil-based feedstock, catalysts, additives and monomer feedstock. These risks can arise from the intrinsic characteristics of the products involved (flammability, toxicity, or long-term environmental impacts such as greenhouse gas emissions and risks of various forms of pollution and contamination of the soil and the groundwater), their use, emissions and discharges resulting from their manufacturing process, and from recycling or disposing of materials and wastes at the end of their useful life.

As for transportation activities related to all Eni s segments of operations, the type of risk depends not only on the hazardous nature of the products transported, but also on the transportation methods used (mainly pipelines, maritime, river-maritime, rail, road, gas distribution networks), the volumes involved and the sensitivity of the regions through which the transport passes (quality of infrastructure, population density, environmental considerations). All modes of transportation of hydrocarbons are particularly susceptible to a loss of containment of hydrocarbons and other hazardous materials, and, given the high volumes involved, could present a significant risk to people and the environment.

The Company invests significant resources in order to upgrade the methods and systems for safeguarding the safety and health of employees, contractors and communities, and the environment; to prevent risks; to comply with applicable laws and policies; and to respond to and learn from unexpected incidents. Eni seeks to minimize these operational risks by carefully designing and building facilities, including wells, industrial complexes, plants and equipment, pipelines, storage sites and distribution networks, and managing its operations in a safe, compliant and reliable manner. Failure to manage these risks could effectively result in unexpected incidents, including releases or oil spills, blowouts, fire, mechanical failures and other incidents resulting in personal injury, loss of life, environmental damage, legal liabilities and/or damage claims, destruction of crude oil or natural gas wells as well as damage to equipment and other property, all of which could lead to a disruption in operations. Eni s operations are often conducted in difficult and/or environmentally sensitive locations such as the Gulf of Mexico, the Caspian Sea and the Arctic, in which the consequences of any incident could be greater than in other locations. Eni also faces risks once production is discontinued, because our activities require environmental site remediation.

Furthermore, in certain situations where Eni is not the operator, the Company may have limited influence and control over third parties, which may limit our ability to manage and control such risks. The Company maintains insurance to protect itself against the risk of damage to Company property and/or business interruption to the Company s main refining and petrochemical sites. In addition, the Company also maintains worldwide third-party liability insurance coverage for all of its subsidiaries. Management believes that its insurance coverage is in line with industry practice and sufficient to cover normal risks in its operations. However, the Company is not insured against all potential risks. In the event of a major environmental disaster, for example, Eni s liability may exceed the maximum coverage provided by its third-party liability insurance. The loss Eni could suffer in the event of such disaster would depend on all the facts and circumstances of the event and would be subject to a whole range of uncertainties, including legal uncertainty as to the scope of liability for consequential damages, which may include economic damage not directly connected to the disaster.

The occurrence of the above mentioned events could have a material adverse impact on the Group business, competitive position, cash flow, results of operations, liquidity, future growth prospects, shareholders return and damage the Group reputation.

The Company cannot guarantee that it will not suffer any uninsured loss and there can be no guarantee, particularly in the case of a major environmental disaster or industrial accident, that such loss would not have a material adverse effect on the Company.

Risks associated with the exploration and production of oil and natural gas

The exploration and production of oil and natural gas require high levels of capital expenditures and are subject to natural hazards and other uncertainties, including those relating to the physical characteristics of oil and gas fields. A description of the main risks facing the Company s business in the exploration and production of oil and gas is provided below.

(i) Eni s oil and natural gas offshore operations are particularly exposed to health, safety, security and environmental risks

Eni has material operations relating to the exploration and production of hydrocarbons located offshore. In 2013, approximately 55% of our total oil and gas production for the year derived from offshore fields, mainly in Egypt, Libya, Norway, Italy, Angola, Congo, the Gulf of Mexico, United Kingdom and Nigeria. Offshore operations in the oil and gas industry are inherently riskier than onshore activities. As the Macondo accident in the Gulf of Mexico has shown, the potential impacts of offshore accidents and spills to health, safety, security and the environment can be catastrophic due to the objective difficulties in handling hydrocarbons containment and other factors. Further, offshore operations are subject to marine perils, including severe storms and other adverse weather conditions and vessel collisions, as well as interruptions or termination by governmental authorities based on safety, environmental and other considerations. Failure to manage these risks could result in injury or loss of life, damage to property, environmental damage, and could result in regulatory action, legal liability, loss of revenues and damage to our reputation and could have a material adverse effect on our operations or financial condition.

(ii) Exploratory drilling efforts may be unsuccessful

Exploration drilling for oil and gas involves numerous risks including the risk of dry holes or failure to find commercial quantities of hydrocarbons. The costs of drilling, completing and operating wells have margins of uncertainty, and drilling operations may be unsuccessful as a result of a variety of factors, including geological play

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failure, unexpected drilling conditions, pressure or heterogeneities in formations, equipment failures, blowouts and other forms of accidents, and shortages or delays in the delivery of equipment. The Company also engages in exploration drilling activities offshore and also in deep and ultra-deep waters, in remote areas, in environmentally-sensitive locations (such as the Barents Sea). In these locations we generally experience more challenging conditions and incur higher exploration costs than onshore. Failure to discover commercial quantities of oil and natural gas could have an adverse impact on Eni s future growth prospects, results of operations and liquidity. Because Eni plans to make investments in executing high-profile and high-risk exploration projects, it is likely that Eni will incur exploration and dry hole expenses in future years. These high-profile and high-risk projects generally involve sizeable plays located in deep and ultra-deep waters or at higher depths where operations are more challenging and costly than in other areas. Furthermore, deep and ultra-deep water operations may require significant time before commercial production of discovered reserves can commence, increasing both the operational and financial risks associated with these activities. The Company plans to conduct exploration projects offshore West Africa (Angola, Nigeria, Congo and Gabon), East Africa (Mozambique and Kenya), South-East Asia (Indonesia, Vietnam and other locations), Australia, the Barents Sea, the Black Sea and the Mediterranean (Cyprus). In 2013, the Company spent approximately euro 1.9 billion to conduct exploration projects and it plans to spend approximately euro 1.4 billion on average in the next four-year plan on exploration activities. Unsuccessful exploration activities and failure to discover additional commercial reserves could reduce future production of oil and natural gas which is highly dependent on the rate of success of exploratory activity.

(iii) Development projects bear significant operational risks which may adversely affect actual returns

Eni is executing several development projects to produce and market hydrocarbon reserves. Certain projects target the development of reserves in high-risk areas, particularly offshore and in remote and hostile environments or environmentally sensitive locations. Eni s future results of operations and liquidity depend heavily on its ability to implement, develop and operate major projects as planned. Key factors that may affect the economics of these projects include:

- the outcome of negotiations with co-venturers, governments and state-owned companies, suppliers, customers or others, including, for example, Eni s ability to negotiate favorable long-term contracts to market gas reserves;
- the development of reliable spot markets that may be necessary to support the development of particular production projects, or commercial arrangements for pipelines and related equipment to transport and market hydrocarbons;
- timely issuance of permits and licenses by government agencies;
- the Company s relative size compared to its main competitors which may prevent it from participating in large-scale projects or affect its ability to reap benefits associated with economies of scale, for example by obtaining more favorable contractual terms by suppliers of equipment and services;
- the ability to carefully carry out front-end design engineering at any development projects so as to prevent the occurrence of technical inconvenience during the execution phase;
- delays in manufacturing and delivery of critical equipment, or shortages in the availability of such equipment, causing cost overruns and delays;
- risks associated with the use of new technologies and the inability to develop advanced technologies to maximize the recoverability rate of hydrocarbons or gain access to previously inaccessible reservoirs;
- poor performance in project execution on the part of international contractors who are awarded project construction activities generally based on the EPC (Engineering, Procurement and Construction) - turn key contractual scheme. We believe this kind of risk may be due to lack of contractual flexibility, poor quality of front-end design engineering and commissioning delays;
- changes in operating conditions and cost overruns. In recent years, the industry has been impacted by escalating costs of certain critical productive factors including specialized workforce, procurement costs and costs for leasing

third-party equipment or purchase services such as drilling rigs as a result of industry-wide cost inflation, bottlenecks and other constraints in the worldwide production capacity available to build critical equipment and facilities and growing complexity and scale of projects, including environmental and safety costs. Furthermore, there has been an evolution in the location of our projects, as Eni has been discovering increasingly important volumes of reserves in remote and harsh locations or environmentally sensitive locations (i.e. the Barents Sea, Alaska, the Gulf of Mexico, the Caspian Sea) where Eni is experiencing significantly higher operating costs and environmental, safety and other costs than in other locations. The Company expects that costs in its upstream operations will continue to rise in the foreseeable future;

the actual performance of the reservoir and natural field decline; and

the ability and time necessary to build suitable transport infrastructures to export production to final markets.

Poor project execution, inadequate front-end engineering, delays in the achievement of critical events and production start-up, and differences between scheduled and actual timing, as well as cost overruns may adversely affect the economic returns of our development projects. Failure to successfully deliver major projects could negatively impact results of operations, cash flow and the achievement of short-term targets of production growth. Finally, development and marketing of hydrocarbons reserves typically require several years after a discovery is made. This is because a development project involves an array of complex and lengthy activities, including appraising a discovery in order to evaluate its commercial potential, sanctioning a development project and building and commissioning related facilities. As a consequence, rates of return for such long-lead-time projects are exposed to the volatility of oil and gas prices and costs which may be substantially different from the prices and costs assumed when the investment decision was actually made, leading to lower rates of return. In addition, projects executed with partners and co-venturers reduce the ability of the Company to manage risks and costs, and Eni could have limited influence over and control of the operations, behaviors and performance of its partners. Furthermore, Eni may not have full operation control of the joint ventures in which it participates and may have exposure to counterparty credit risk and disruption of operation and strategic objectives due to the nature of its relationships.

We have experienced a few delays at a number of development projects located mainly in Algeria, the United Kingdom, Angola and Norway. Those delays were attributable to execution issues and delivery of critical equipment reflecting capacity constraints. These events have impacted the timing profile of our planned production growth in the short term.

In case the Company is unable to develop and operate major projects as planned, particularly if the Company fails to accomplish budgeted costs and time schedules, it could incur significant impairment charges associated with reduced future cash flows of those projects on capitalized costs.

(iv) Inability to replace oil and natural gas reserves could adversely impact results of operations and financial condition

Eni s results of operations and financial condition are substantially dependent on its ability to develop and sell oil and natural gas. Unless the Company is able to replace produced oil and natural gas, its reserves will decline. In addition to being a function of production, revisions and new discoveries, the Company s reserve replacement is also affected by the entitlement mechanism in its Production Sharing Agreements (PSAs) and similar contractual schemes. In accordance with such contracts, Eni is entitled to a portion of a field s reserves, the sale of which is intended to cover expenditures incurred by the Company to develop and operate the field. The higher the reference prices for Brent crude oil used to estimate Eni s proved reserves, the lower the number of barrels necessary to recover the same amount of expenditures. Future oil and gas production is dependent on the Company s ability to access new reserves through new discoveries, application of improved techniques, success in development activity, negotiation with countries and other owners of known reserves and acquisitions. In a number of reserve-rich countries, national oil companies control a large portion of oil and gas reserves that remain to be developed. To the extent that national oil companies decide to develop those reserves without the participation of international oil companies or if the Company fails to establish partnership with national oil companies, Eni s ability to access or develop additional reserves will be limited.

An inability to replace produced reserves by finding, acquiring and developing additional reserves could adversely impact future production levels and growth prospects. If Eni is unsuccessful, it may not meet its long-term targets of production growth and reserve replacement, and Eni s future total proved reserves and production will decline, negatively affecting Eni s future results of operations and financial condition.

(v) Changes in crude oil and natural gas prices may adversely affect Eni s results of operations

The exploration and production of oil and gas is a commodity business with a history of price volatility. The single largest variable that affects the Company s results of operations and financial condition is crude oil prices. Lower crude oil prices have an adverse impact on Eni s results of operations and cash flows. Eni generally does not hedge exposure of the future expected cash flows of the Group reserves to movements in crude oil price. As a consequence, Eni s profitability depends heavily on crude oil and natural gas prices. Crude oil and natural gas prices are subject to international supply and demand and other factors that are beyond Eni s control, including among other things:

(i) the control on production exerted by the Organization of the Petroleum Exporting Countries (OPEC) member countries which control a significant portion of the world s supply of oil and can exercise substantial influence on price levels;

(ii) global geopolitical and economic developments, including sanctions imposed on certain oil-producing countries on the basis of resolutions of the United Nations or bilateral sanctions or disruptions due to local instability. We believe that crude oil prices were supported in 2013 by a number of interruptions in the output flows that occurred in countries like Libya, Nigeria and Syria due to local issues driven by political and social instability;

(iii) global and regional dynamics of demand and supply of oil and gas. We believes that global oil demand will grow at a moderate pace in the foreseeable future due to sluggish economic activity in Europe and other macroeconomic uncertainties, and more efficient use of fuels and energy in OECD countries;

(iv) prices and availability of alternative sources of energy. Eni believes that gas demand in Europe has been significantly impacted by a shift to the use of coal in firing power plants due to cost advantages compared to

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gas, as well as the rising contribution of renewable energies in satisfying energy requirements. Eni expects those trends to continue in the future;

(v) governmental and intergovernmental regulations, including the implementation of national or international laws or regulations intended to limit greenhouse gas emissions, which could impact the prices of hydrocarbons; and

(vi) success in developing and applying new technology.

All these factors can affect the global balance between demand and supply for oil and prices of oil.

We estimate that movements in oil prices impact our results with respect to approximately 50% of our current production. Of the remaining portion, 35% is derived from production sharing contracts and is substantially unaffected by crude oil price movements which instead impact the Company s volume entitlements (see paragraph Inability to replace oil and natural gas reserves could adversely impact results of operations and financial condition above). We expect that the Company results of operations from 2014 onwards will reflect our decision late in 2013 to fully exploit the benefits of the natural hedging occurring between our Exploration & Production and Gas & Power segments. We estimate that going forward the exposure to changes in crude oil prices of approximately 8-10% of our production will be offset by equal and opposite changes to the procurement costs of gas in our long-term supply contracts which, based on the existing agreements, index the cost of gas to crude oil prices. In previous reporting periods we entered into commodity derivatives to protect margins on gas sales in our Gas & Power business from exposure to crude oil changes due to the progressive de-coupling that has occurred between the selling prices which have been indexed to spot prices and the procurement oil-linked costs of gas, resulting in a growing exposure of the Gas & Power segment to crude oil price movements. Late in 2013, we discontinued this hedging policy with a view to exploiting the natural hedge provided by our equity production of crude oil. We expect that the operating results of the Gas & Power segment will be more volatile as long as the gas purchase costs remain indexed the oil prices; at the same time the Group results as a whole will be less exposed to crude oil prices movements than in past reporting periods. See the risk factors Exposure to financial risks below.

Lower oil and gas prices over prolonged periods may also adversely affect Eni s results of operations and cash flows by: (i) reducing rates of return of development projects either planned or being implemented, leading the Company to reschedule, postpone or cancel development projects, or accept a lower rate of return on such projects; (ii) reducing the Group s liquidity, entailing lower resources to fund expansion projects, further dampening the Company s ability to grow future production and revenues; and (iii) triggering a review of future recoverability of the Company s carrying amounts of oil and gas properties, which could lead to the recognition of significant impairment charges.

(vi) Eni expects that tightening regulation in oil and gas activities following the Macondo accident will lead to rising compliance costs and other restrictions

The production of oil and natural gas is highly regulated and is subject to conditions imposed by governments throughout the world in matters such as the award of exploration and production interests, the imposition of specific drilling and other work obligations, income taxes and taxes on production, environmental protection measures, control over the development and abandonment of fields and installations, and restrictions on production. Following the Macondo accident in the Gulf of Mexico, Eni expects that governments throughout the world will implement stricter regulation on environmental protection, risk prevention and other forms of restrictions to drilling and other well operations. These new regulations and legislation, as well as evolving practices, could increase the cost of compliance and may also require changes to our drilling operations and exploration and development plans and may lead to higher royalties and taxes.

(vii) Uncertainties in estimates of oil and natural gas reserves

Several uncertainties are inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures. The accuracy of proved reserve estimates depends on a number of factors, assumptions and variables, among which the most important are the following:

- the quality of available geological, technical and economic data and their interpretation and judgment;
- projections regarding future rates of production and costs and timing of development expenditures;
- changes in the prevailing tax rules, other government regulations and contractual conditions;
- results of drilling, testing and the actual production performance of Eni s reservoirs after the date of the estimates which may drive substantial upward or downward revisions; and
- changes in oil and natural gas prices which could affect the quantities of Eni s proved reserves since the estimates of reserves are based on prices and costs existing as of the date when these estimates are made. Lower oil prices or the projections of higher operating and development costs may impair the ability of the Company to economically produce reserves leading to downward reserve revisions.

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In particular the reserve estimates are subject to revisions as prices fluctuate due to the cost recovery mechanism under the Company s production sharing agreements and similar contractual schemes.

Many of these factors, assumptions and variables involved in estimating proved reserves are subject to change over time therefore impacting the estimates of oil and natural gas reserves. Accordingly, the estimated reserves reported as of the end of the period covered by this filing could be significantly different from the quantities of oil and natural gas that will ultimately be recovered. Any downward revision in Eni s estimated quantities of proved reserves would indicate lower future production volumes, which could adversely impact Eni s results of operations and financial condition.

(viii) Oil and gas activity may be subject to increasingly high levels of income taxes

The oil and gas industry is subject to the payment of royalties and income taxes which tend to be higher than those payable in many other commercial activities. In addition, in recent years, Eni has experienced adverse changes in the tax regimes applicable to oil and gas operations in a number of countries where the Company conducts its upstream operations. As a result of these trends, management estimates that the tax rate applicable to the Company s oil and gas operations is materially higher than the Italian statutory tax rate for corporate profit which currently stands at 38%. The tax rate of the Company s Exploration & Production segment for the fiscal year 2013 was approximately 60%.

Management believes that the marginal tax rate in the oil and gas industry tends to increase in correlation with higher oil prices which could make it more difficult for Eni to translate higher oil prices into increased net profit. However, the Company does not expect that the marginal tax rate will decrease in response to falling oil prices. Adverse changes in the tax rate applicable to the Group profit before income taxes in its oil and gas operations would have a negative impact on Eni s future results of operations and cash flows.

In the current uncertain financial and economic environment, governments are facing greater pressure on public finances, which may increase their motivation to intervene in the fiscal framework for the oil and gas industry, including the risk of increased taxation, nationalization and expropriations.

Eni s results depend on its ability to identify and mitigate the above mentioned risks and hazards which are inherent to Eni s operation.

Political considerations

A substantial portion of Eni s oil and gas reserves and gas supplies are located in countries which are politically, socially and economically less stable than OECD countries. Therefore Eni is exposed to risks of material disruptions to its operations in those less stable countries. As of December 31, 2013, approximately 78% of Eni s proved hydrocarbon reserves were located in such countries and 62% of Eni s supplies of natural gas came from countries outside OECD countries.

Adverse political, social and economic developments in any of those less stable countries may negatively affect Eni s ability to continue operating in an economic way, either temporarily or permanently, and Eni s ability to access oil and gas reserves. In particular, Eni faces risks in connection with the following issues:

(i) lack of well-established and reliable legal systems and uncertainties surrounding enforcement of contractual rights;

(ii) unfavorable developments in laws, regulations and contractual arrangements leading, for example, to expropriations or forced divestitures of assets and unilateral cancellation or modification of contractual terms. Eni is facing increasing competition from state-owned oil companies who are partnering Eni in a number of oil and gas projects and properties in the host countries where Eni conducts its upstream operations. These state-owned oil companies can change contractual terms and other conditions of oil and gas projects in order to obtain a larger profit share from a given project, thereby reducing Eni s profit share. Furthermore, as of December 31, 2013, receivables for euro 575 million relating to cost recovery under certain petroleum contracts in a non-OECD country were the subject of an arbitration proceeding;

(iii) restrictions on exploration, production, imports and exports;

(iv) tax or royalty increases (including retroactive claims); and

(v) civil and social unrest, internal conflicts and other forms of political instability, sabotages, strikes, acts of violence and incidents. These risks could result in disruptions in the economic activity, loss of output, plant closure, project delays, the loss of our personnel or assets, cause us to evacuate our personnel from certain countries, cause us to increase spending on security worldwide, disrupt financial and commercial markets, including the supply of and pricing for oil and natural gas, and generate greater political and economic instability in some of the geographic areas in which we operate. Areas where we operate that have significant risk include, but are not limited to: the Middle East, Libya, Egypt, Algeria, Nigeria, Angola, Indonesia, Kazakhstan, Russia, and Venezuela. In addition, any possible reprisals as a consequence of military or other action, such as acts of terrorism in the United States or elsewhere, could have a material adverse effect on our business, consolidated results of operations, and consolidated financial condition. In 2013, our expected production levels in Nigeria, Libya and Algeria were negatively impacted by continuing social unrest, protests, strikes, acts of sabotage and theft which forced us to disrupt or reduce our producing activities with an estimated cumulative loss of output of 110 KBOE/d for the year, negatively affecting our results of operations and cash flow. In 2013, our production in Libya was 219 KBOE/d, down by 13% from 2012; in Nigeria it was 120 KBOE/d, down by 19% from 2012. Looking forward, we expect those risks will continue to affect our operations in those countries and we do not plan for any significant recovery in our production plateau in both countries over the next couple of years. For more information about the status of our operations in Libya see the paragraph below.

While the occurrence of those events is unpredictable, it is likely that the occurrence of such events could cause Eni to incur material production losses or facility disruptions, and thus adversely impact Eni s results of operations and cash flow.

Risks associated with continuing political instability in North Africa and the Middle East

As at the end of 2013, approximately 28% of the Company s proved oil and gas reserves were located in North Africa and the Middle East. In 2011, several North African and Middle Eastern oil producing countries experienced an extreme level of political instability that resulted in changes in governments, unrest and violence and consequential economic disruptions.

The instability of the socio-political framework in those countries still represents an area of concern involving risks and uncertainties for the foreseeable future; particularly in Libya in 2013, Eni s production performance was negatively impacted due to force majeure events reflecting ongoing instability in the socio-political context of the Country. It is worth mentioning that in Libya Eni is currently engaged in the recovery of the full production plateau at its producing assets in the Country, following the internal conflict of 2011 that forced the Company to shut down almost all its producing facilities including gas exports for a period of about 8 months with a material impact on production volumes and operating results of that year. Due to the complexity of the transition period, which the Country is currently undergoing, Eni is still in the process of restoring the full production plateau. For the full year 2013 Eni s facilities in Libya produced the level of 219 KBOE/d, which is lower than the pre-crisis production plateau of approximately 270 KBOE/d attained in 2010.

In Egypt the internal situation seems to be still complex and in 2013, a new wave of political unrest and civil clashes occurred, jeopardizing the economic activities in the Country. However, the Company has not experienced any disruption at its producing activities in the Country to date.

The Company believes that the political outlook in North Africa and the Middle East remains an area of risk for the Company s operations, results and strategic development.

Risks associated with our presence in sanction targets

Eni is currently conducting certain residual oil and gas operations in Iran. The legislation and other regulations in the United States and the European Union that target Iran and persons who have certain dealings with Iran may lead to the imposition of sanctions on any persons doing business in Iran or with Iranian counterparties, unless specific authorizations, exceptions and assurances apply, as it is currently the case for Eni.

United States measures towards Iran

The United States enacted the Iran Sanctions Act of 1996 (ISA), which required the President of the United States to impose sanctions against any entity that is determined to have engaged in certain activities, including investment in Iran s petroleum sector. The ISA was amended in July 2010 by the Comprehensive Iran Sanctions, Accountability and Divestment Act of 2010 (CISADA) which sanctions activities that either: (i) facilitate the maintenance or expansion of Iran s domestic production of refined petroleum products, or (ii) contribute to the enhancement of Iran s ability to import refined petroleum products.

CISADA expanded the list of sanctions available to the President of the United States while at the same time providing that an investigation need not be initiated, and may be terminated once began, if the President certifies in writing to the U.S. Congress that the person whose activities in Iran were the basis for the investigation is no longer engaging in those activities or has taken significant steps toward stopping the activities, and that the President has received reliable assurances that the person will not knowingly engage in any sanctionable activity in the future.

It should be noted that after passage of CISADA, Eni engaged in discussions with officials of the U.S. State Department, which administers the ISA, regarding Eni s activities in Iran. On September 30, 2010, the U.S. State Department announced that the U.S. Government, pursuant to a provision of the ISA added by CISADA that allows it to avoid making a determination of sanctionability under the ISA with respect to any party that provides certain assurances, would not make such a determination with respect to Eni based on Eni s commitment to end its investments in Iran s energy sector and not to undertake new energy-related activity. The U.S. State Department further indicated at that time that, as long as Eni acts in accordance with these commitments, it will not be regarded as a company of concern for its past Iran-related activities.

The United States maintains however a broad and comprehensive economic sanctions targeting Iran that are administrated by the U.S. Treasury Department s Office of Foreign Assets Control (OFAC sanctions). These sanctions generally restrict the dealings of U.S. citizens and persons subject to the jurisdiction of the United States. In addition, Eni is aware of initiatives by certain U.S. states and U.S. institutional investors, such as pension funds, to adopt or consider adopting laws, regulations or policies requiring divestment from, or reporting of interests in, companies that do business with countries designated as states sponsoring terrorism. CISADA specifically authorized certain state and local Iran-related divestment initiatives. If Eni s operations in Iran are determined to fall within the scope of divestment laws or policies, sales resulting from such divestment laws and policies, if significant, could have an adverse effect on the value of Eni's shares. Even if Eni's activities in and with respect to Iran do not expose it to sanctions or divestment, companies with investments in the oil and gas sectors in Iran may suffer reputational harm as a result of increased international scrutiny.

Between the end of 2011 and 2013, the United States adopted new measures designed to intensify the scope of U.S. sanctions against Iran, in particular related to the Iran s energy and financial sectors.

Such restrictive measures are: the Executive Orders 13590 of November 21, 2011 and 13622 of July 31, 2012, the Iran Threat Reduction and Syrian Human Rights Acts of August 10, 2012 (ITRSHRA), which expanded the ISA/CISADA scope by increasing from three to five the minimum number of sanctions to be imposed in case of violations of the energy sector restrictions; the National Defense Authorization Acts - 2012, related to transactions with the Iranian Central Bank and transactions for the acquisition of Iranian crude oil and the National Defense Authorization Acts - 2013, which, inter alia, adds the shipbuilding sector to those areas subject to sanctions. A waiver was granted to Italy and other EU Member States in March 2012, in September 2013 and lastly renewed in March 2014 for a further 180-day period.

While Eni has no formal assurances that the U.S. State Department s 2010 determination of non-sanctionability under the ISA would similarly extend to sanctions under the measures issued in 2011, 2012 and 2013, during this period, Eni has continued to inform the U.S. State Department of its Iran-related activities. Eni does not believe that its activities in Iran (the completion of existing contracts which were notified to the U.S. Administration when the Special Rule was applied) are sanctionable under such more recent measures described above.

European Union restrictive measures towards Iran

On July 26, 2010, the European Union adopted restrictive measures regarding Iran (referred to as the "EU measures"). Among other things, the supply of equipment and technology is prohibited in the following sectors of the oil and gas industry in Iran: refining, liquefied natural gas, exploration and production. The prohibition extends to technical assistance, training and financing and financial assistance in connection with such items. Transactions arising from contracts signed before the sanctions entered into force are allowed.

On March 23, 2012, the Council of the European Union enacted a regulation, repealing the measures adopted on July 26, 2010, prohibiting the import, transport and purchase of Iranian crude oil and petroleum products. The rules allow for the performance of contracts, entered into force before January 23, 2012, whereby the supply of Iranian crude oil and petroleum products is intended to reimburse outstanding receivables due to entities under the jurisdiction of EU Member States.

In 2012, the Council of the European Union adopted other restrictive measures against Iran including among others: prohibition of the transactions between the European Union and Iranian banks and financial institutions, unless an authorization is granted in advance by the relevant Member State, an embargo on the supply to Iran and use in Iran of key equipment or technology which could be used in the sectors of the oil, natural gas and petrochemical industries, starting from April 15, 2013.

Furthermore, the new measures designate new Iranian entities as subject to the asset freeze, including the Iranian oil and gas industry companies (the National Iranian Oil Co and its subsidiary operating companies).

The European measures provide for a waiver of certain prohibitions (i.e. embargo on oil and gas key technologies, prohibition to supply of vessels for the purpose of transporting Iranian oil, asset freeze of the National Iranian Co and its subsidiaries) in order to perform obligations under contracts entered into before January 23, 2012, which provide for the supply of Iranian crude oil and petroleum products as a reimbursement of outstanding receivables due to entities under the jurisdictions of EU Member States by Iranian counterparties. According to these waivers, Eni received from the competent European Member States Authorities the relevant authorizations in order to carry out its upstream and oil import activities.

Eni has been operating in Iran for several years under four service contracts (South Pars, Darquain, Dorood and Balal, these latter two projects being operated by another international oil company) entered into with the National Iranian Oil Co (NIOC) between 1999 and 2001, and no other exploration and development contracts have been entered into since then. Under such service contracts, Eni has carried out development operations in respect of certain oilfields, and is entitled to recovery of expenditures made, as well as a service fee. All projects mentioned above have been completed or substantially completed; the Darquain project, is in the process of final commissioning and is being handed over to the NIOC. Eni is providing services in advance of the hand-over of the oilfield to NIOC and retains certain technical assistance and service obligations, and an obligation to provide, upon request, spare parts and supplies for field maintenance and operations. In 2013, Eni incurred $2 million to provide such activities and services and does not expect to incur further operating costs in this respect since the relevant obligations are going to expire.

Eni's projects in Iran are currently in the cost recovery phase. Therefore, Eni has ceased making any further investment in the Country and is not planning to make additional capital expenditures in Iran in future years. In 2013, Eni s production in Iran averaged 4 KBOE/d, representing less than 1% of the Eni Group s total production for the year. Eni s entitlement in 2013 represented approximately 3% of the overall production from the oil and gas fields that Eni has developed in Iran. Eni believes that the results from its Iranian activities are immaterial to the Group s results of operations and cash flow.

The Company s Refining & Marketing segment has historically purchased amounts of Iranian crude oil under term contracts and on a spot basis. Eni purchased 976 ktonnes and 498 ktonnes in 2011, and 2012, respectively. Eni paid NIOC $742 million in 2011 and $396 million in 2012. In June 2012, as a consequence of the European restrictive measures Eni ceased to buy Iranian crude oil. In accordance with the European Union sanctions regime, Eni has been authorized by the competent European Authorities to import only volumes necessary to collect outstanding receivables towards Iranian counterparties.

Eni has no involvement in Iran s refined petroleum sector and does not export refined petroleum to Iran.

Finally, Eni s Chemical segment licensed a number of technologies in Iran in past years, relating to plastics/elastomers and relevant raw materials, but it never supplied equipment or materials for plant construction. By April 2013, Eni had suspended all contracts to comply with EU restrictions.

Eni will continue to monitor closely legislative and other developments in the United States and the European Union in order to determine whether its remaining interests in Iran could subject Eni to application of either current or future sanctions under the OFAC sanctions, the ISA, the EU measures or otherwise. If any of its activities in and with respect to Iran are found to be in violation of any Iran-related sanctions, and sanctions are imposed on Eni, it could have an adverse effect on Eni s business, plans to raise financing, sales and reputation.

In previous years Eni has had marginal commercial transactions with Syria

Our contacts with Syria have regarded mainly the purchase of limited amounts of Syrian-originated crude oil and certain preliminary activities under a contract awarded to our partially-owned subsidiary Saipem SpA as described below. All such activities have ceased since 2012.

In 2011, our Refining & Marketing business purchased 243 ktonnes of crude oil from Syrian Petrol Co which we understand to be an affiliate of the Syrian Government. We paid $175 million for those transactions. Those amounts represented less than 1% of total volumes of crude oil purchased by this business segment for the year, which were equal to 31.4 mmtonnes, and the amount paid to Syrian Petrol Co represented significantly less than 1% of our consolidated purchases of goods and raw materials for the year (euro 61 billion). In 2011, we also purchased 165 ktonnes of crude oil for a purchase cost of $123 million from certain international traders who, according to bills of loading and shipping documentation available to us, we believe purchased that crude oil from Syrian companies.

In addition, in 2011, we sold 127 ktonnes of refined products, mainly gasoline, to a Syrian company amounting to $114 million. Those amounts represented significantly less than 1% of our sales volumes of refined products and consolidated net revenues for the year (45 mmtonnes and euro 108 billion, respectively). In 2011, we also sold limited amounts of refined products (61 ktonnes for a consideration of $61 million), mainly gasoline, to certain international traders who, according to bills of loading and shipping documentation available to us, then resold the products to Syrian companies. Finally, in 2011, we executed two time charter contracts for our vessels with international oil companies which involved Syrian ports.

In 2012, we suspended any crude-related operations and sale of refined products with Syria and no further purchases of crude oil from Syrian counterparties or sale of refined products to Syria have been made in 2012, in 2013 and up to date.

In 2011, our partially-owned subsidiary Saipem SpA carried out limited activities relating to the procurement of goods and preliminary arrangements with suppliers as part of a contract awarded in 2010 by Dijla Petroleum Co, which is an affiliate of the Syrian National Oil Co. This contract is a lump sum, turn-key contract to build a central processing facility with a daily capacity of 50,000 barrels of liquids at the Khurbet East oil field, for approximately euro 100 million. No activities have been executed in situ and the contract has then been suspended indefinitely due to security issues.

Other than as described above, Eni is not currently investing in the Country, and it has no contractual arrangements in place to invest in the Country.

We continue to believe that our operations in Syria have historically been and continue to be immaterial to our Group s consolidated revenues, operating profit, cash flow and assets.

Situation in Russia and Ukraine

Eni is closely monitoring developments of the situation in Ukraine and Crimea and any related regulations and/or economic sanctions that could be adopted by the authorities. It is possible that wider sanctions covering the Russian energy, banking and/or finance industries may be implemented. Among other activities, Eni: is part of a strategic cooperation agreement for exploration activities in the Russian sections of the Barents and Black Sea; holds a 50% interest in the Blue Stream pipeline (which links the Russian and Turkish coasts). Further sanctions imposed on Russia from the international community, such as, for example, enacting restrictions on purchases of Russian gas or restricting dealings with Russian counterparties could adversely impact Eni s results of operations and cash flow.

Cyclicality of the petrochemical industry

The petrochemical industry is subject to fluctuations in demand in response to macroeconomic cycles, leading to volatile results of operations and cash flow. It is a highly competitive industry due to lack of entry barriers, product commoditization and excess capacity, which may exacerbate the impact of any demand downturns on the results reported by our Chemical business. Eni s chemical operations have been facing increasing competition from Asian companies and the petrochemical arm of national oil companies based in the Middle East which can leverage on long-term competitive advantages in terms of lower operating costs and cheaper feedstock costs. In particular, Eni s competitors based in the Middle East are benefiting from the large availability of gas-based feedstock which provides a cost advantage compared to the oil-based feedstock used at Eni s operations. Management also expects that U.S.-based petrochemical companies will regain competitiveness in the medium-term leveraging on the large domestic availability of raw materials which can be extracted from shale gas.

Eni s chemical operations are located mainly in Italy and Western Europe where the expenses to comply with environmental, safety and security rules may be higher than in most Asian countries due to an established regulatory framework and public environmental sensitivity. Additionally, Eni s petrochemical operations lack sufficient scale and competitiveness at a number of sites due in part to geographic location and other structural weaknesses. Due to poor industry fundamentals, intense competitive pressures, high feedstock costs, coupled with company-specific issues, Eni s chemical operations incurred losses at the operating level in each of the latest three years (euro 725 million, euro 681 million and euro 424 million in 2013, 2012 and 2011, respectively). Management expects that in the foreseeable future results and cash flow at our chemical business could be adversely affected by a weak economic outlook in Italy and Europe. Furthermore, rising costs of oil-based feedstock represent a risk to the profitability of the Company s petrochemical operations as it may be difficult to preserve product margins due to the high level of competition in the industry and the commoditized nature of many of Eni s products.

Risks in the Company Gas & Power business

(i) Risks associated with the trading environment and competition in the industry

2013 marked the third consecutive year of operating losses at our Gas & Power segment which was driven by a prolonged demand downturn, strong competitive pressures and gas oversupplies. The Company expects those structural headwinds to continue to adversely impact results of operations and liquidity for the foreseeable future.

The Company s gas marketing business reported operating losses and negative cash flow in each of the latest three years driven by changed competitive dynamics in the European gas sector on the back of a prolonged demand downturn. Gas demand has been severely hit by the economic slowdown in Europe and, more importantly, a steep fall of gas consumption in the thermoelectric sector. The latter trend was affected by an ongoing expansion of renewable sources of electricity which have benefited from governmental subsides across Europe, whilst coal has displaced gas on a large scale in firing power plants due to cost advantages and lowering rates for obtaining emission allowances in Europe due to the downturn. Coal prices have seen a dramatic fall in recent years due to a massive glut of coal on a global scale. In the face of weak demand, supplies on the European marketplace have continued to increase due to a number of factors. First of all, before the beginning of the downturn gas wholesaler operators in Europe grossly overestimated the projected growth rates in demand and committed to purchase large amounts of gas under long-tem supply contracts with producing countries also bearing the volume risk as a result of the take-or-pay clause of those contracts. They also built large pipeline upgrade to import gas to Europe. Secondly, several LNG projects came on stream, which improved the liquidity of spot markets. Finally, the fact that the United States has reduced their dependence on LNG imports due to large increases in the domestic production of shale gas. This latter development has further added to global LNG supplies. These trends have driven the expansion of very liquid continental hubs where spot prices have become the prevailing benchmark of sale contracts, particularly in the industrial and thermoelectric segments. Spot prices have been on a downtrend over the last few years reflecting oversupplies and weak demand. This trend has hit the profitability of European gas marketing operators, including Eni. Particularly, our results of operations for 2013 were adversely impacted by a faster than anticipated alignment between continental benchmarks and spot prices at Italian hubs leading to sharply lower price realizations in the Italian wholesale market. In addition trends in sales prices have not been reflected in the procurement costs of gas supplies as European gas operators procure their gas supplies under long-term contracts with producing countries whereby the cost of gas is generally indexed to the price of crude oil and other derivatives which have diverged from trends in gas spot prices. Therefore wholesale margins on gas were squeezed due to this decoupling which has occurred between spot prices and the oil-linked costs of purchased gas. Adding to the pressure, reduced sales opportunities due to weak demand forced operators to compete even more aggressively on pricing to limit the financial risks associated with the take-or-pay clause provided by the long-term supply contracts. On their part, large clients adopted opportunistic supply patterns, in order to take advantage of the large availability of spot gas. Finally governmental administrations in several European countries have started to review the indexation mechanism of supply tariffs in the retail sector in order to make residential customers benefit from the ongoing trend in gas spot markets. In Italy, administrative bodies have already enacted effective October 1, 2013 a new indexation mechanism of the cost of the raw material in pricing formulas of the safeguarded retail market whereby the cost of gas in currently indexed to spot prices thus replacing the previous oil-linked indexation. This development will reduce our margins in the residential sector. See "Regulation of the natural gas market in Italy" below.

We forecast that market conditions will remain unfavorable in the gas sector in Italy and Europe for the foreseeable future due to the structural headwinds described above, volatile commodity prices and lack of visibility. We anticipate a number of risk factors to the profitability outlook of the Company s gas marketing business over the next two to three years. Those include weak demand growth due to a projected slow recovery in the Euro-zone and macroeconomic uncertainties, declining thermoelectric consumption due to inter-fuel competition, continuing oversupplies and strong competition. Eni believes that those trends will negatively impact the gas marketing business future results of operations and cash flows by reducing gas selling prices and margins, also considering Eni s obligations under its take-or-pay supply contracts (see below).

The Company is seeking to improve its cost competitiveness by renegotiating more favorable contractual terms with our long-term suppliers. If we fail to achieve this, our profitability could be adversely affected

The Company s long-term supply contracts provide clauses whereby the parties are entitled to renegotiate pricing terms and other contractual conditions from time to time to reflect a changed market environment. The Company is currently seeking to renegotiate better terms and pricing of our long-term supply contracts to align its cost structure to prices prevailing in the marketplace in order to preserve the profitability of its gas operations and to reduce the annual minim take of its contracts dictated by the take-or-pay clause in order to be more flexible in the current weak demand environment. If Eni fails to obtain the planned benefits, future results and cash flow could be adversely affected. Furthermore, management believes that the results of the Gas & Power segment will become more volatile and unpredictable in future years as contractual renegotiations take time to define, possibly leading to large one-off price adjustments recorded in the reporting period when the new terms are agreed upon. In addition, in case the parties fail to arrange renewed contractual terms, both of them may seek an arbitration ruling, which would increase the uncertainty regarding the final outcome of the renegotiation process. A number of clients, to whom Eni supply on long-term basis, have already requested, and may request in the future, price revisions and other contractual changes.

The Company expects that current imbalances between demand and supply in the European gas market will persist for sometime

Gas demand fell significantly in 2013, down by 7% and 1% in Italy and Europe respectively, driven by the economic downturn and sharply lower gas consumption in the thermoelectric sector. While there are signs that demand may have finally bottomed by end of 2013, there is still little visibility on the evolution of gas demand due to the risks and uncertainties associated with a number of ongoing trends:

- uncertainties and volatility in the macroeconomic cycle; particularly the anticipated slow recovery of the economic activity in Europe will weigh on the prospects of any sustainable rebound in gas demand;
- EU policies intended on one hand to reduce greenhouse gas emissions which should negatively impact the consumption of coal in producing electricity to advantage of gas; on the other hand continuing subsides to promote the development of renewable energy sources might jeopardize a recovery in gas-fired thermoelectric production which management still consider to be potentially the main engine of growth in gas demand;
- concrete developments following the announcement made by certain national governments in Europe to shut down nuclear plants; and
- growing adoption of consumption patterns and life-styles characterized by wider sensitivity to energy efficiency.

Against these ongoing trends, management has revised downward its estimates for gas demand: an almost flat demand environment in Italy and Europe has been assumed up to 2017 compared to previous years assumptions made in the industrial plan 2013-2016 of a growth rate of 1.7-1.8%. It is worth mentioning that the projected levels of European gas demand in 2017 are significantly lower than the pre-crisis levels registered in 2008 as a result of weak fundamentals.

The projected moderate dynamics in demand might not be enough to balance the current situation of oversupply in the marketplace over the next two to three years according to management s estimates. Gas supplies have been built up in recent years as new, large investments to upgrade import pipelines to Europe have come online from Russia and Algeria and gas wholesalers have contracted important volume of supplies under long-tem arrangement in past years, forecasting certain trends in demand which actually failed to materialize. Furthermore, in the near future management expects the start-up of new infrastructures in various European entry points which will add large amounts of new import capacity over the next few years. Those include a new line of the North Stream pipeline connecting Russia to Germany through the Baltic Sea, as well as new LNG facilities. In Italy, the gas offered will increase moderately in the future as a new LNG plant is expected to start operations in Livorno with a 4 BCM treatment capacity and effects are in place of Law Decree No. 130/2010 about storage capacity which is expected to increase by 4 BCM by 2015. Those negatives will be partially tempered by a declining availability of LNG on a worldwide scale which has been absorbed by growing energy requirements from East Asian economies. In addition Europe s internal production is maturing. However, in the long-term management expects the start-up of an array of LNG projects which are expected to contribute significantly to global LNG supplies, as well as an increasing willingness as part of the United States to support the development of gas exports from the domestic production. Overall we expect a well supplied global gas market in the long term.

These trends represent risks to the Company s future results of operations and cash flows in its gas business.

Current, negative trends in gas demands and supplies may impair the Company s ability to fulfill its minimum collection obligations in connection with its take-or-pay, long-term gas supply contracts

In order to secure long-term access to gas availability, particularly with a view of supplying the Italian gas market and anticipating certain trends in gas demand which actually failed to materialize, Eni has signed a number of long-term gas supply contracts with national operators of key producing countries that supply the European gas markets. These contracts have been ensuring approximately 80 BCM of gas availability from 2010 (including the Distrigas portfolio of supplies and excluding Eni s other subsidiaries and affiliates) with an average residual life of approximately 14 years and a pricing mechanism that indexes the cost of gas to the price of crude oil and its products (gasoil, fuel oil, etc.). These contracts include take-or-pay clauses whereby the Company is required to collect minimum, preset volumes of gas in each year of the contractual term or, in case of failure, to pay the whole price, or a fraction of that price, up to the minimum contractual quantity. The take-or-pay clause entitles the Company to collect pre-paid volumes of gas in later years during the period of contract execution. Amounts of cash prepayments and time schedules for collecting pre-paid gas vary from contract to contract. Generally, cash prepayments are calculated on the basis of the energy prices current in the year when the Company is scheduled to purchase the gas, with the balance due in the year when the gas is actually purchased. Amounts of prepayments range from 10 to 100% of the full price.

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The right to collect pre-paid gas expires within a ten-year term in some contracts or remains in place until contract expiration in other arrangements. In addition, the right to collect the pre-paid gas can be exercised in future years provided that the Company has fulfilled its minimum take obligation in a given year and within the limit of the maximum annual quantity. In this case, Eni will pay the residual price calculating it as the percentage that complements 100%, based on the arithmetical average of monthly base prices current in the year of the collection. Similar considerations apply to ship-or-pay contractual obligations.

Management believes that the current market outlook pointing to weak gas demand growth and large gas availability, the possible evolution of sector-specific regulation, as well as strong competitive pressures in the marketplace represent risk factors to the Company s ability to fulfill its minimum take obligations associated with its long-term supply contracts.

Since the beginning of the downturn in the European gas market late in 2009, Eni has incurred the take-or-pay clause as the Company collected lower volumes than its minimum take obligations in each of those years accumulating deferred costs amounting to euro 1.9 billion and has paid the relevant cash advances.

Considering ongoing market trends and the Company s outlook for its sales volumes which are anticipated to remain flat or to decrease slightly in 2014 and in subsequent years, management believes that the Company s ability to fulfill its minimum take obligations under current take-or-pay contracts might be at risk. In order to reduce the financial risk the Company may decide to dispose of its gas availability deriving from its minimum take obligations by selling that gas at lower prices thus negatively impacting the results of operations.

In addition to the financial risk, failure to collect the contractual minimum amounts exposes the Company to a price risk, because the purchase price Eni will ultimately be required to pay is based on future energy prices which may be higher than the energy prices prevailing when the take-or-pay obligation arose. In addition, Eni is subject to the risk of not being able to dispose of pre-paid volumes should the total addressable market be smaller than the Company s gas availability in the relevant period. Furthermore, the deferred costs recognized in the balance sheet is stated at the purchase cost or the net realizable value, whichever is lower, thus exposing the Company to losses in case gas prices continue to fall. Finally, the Company expects to incur financing costs considering the cash advances already paid to its suppliers.

As a result of those risks, the Company s selling margins, results of operations and cash flow may be negatively affected.

(ii) Risks associated with sector-specific regulations in Italy

Risks associated with the regulatory powers entrusted to the Italian Authority for Electricity and Gas in the matter of pricing to residential customers

The Authority for Electricity and Gas (the AEEG) is entrusted with certain powers in the matter of natural gas pricing. Specifically, the AEEG holds a general surveillance power on pricing in the natural gas market in Italy and the power to establish selling tariffs for the supply of natural gas to residential and commercial users consuming less than 50,000 CM/y (as provided for by Resolution ARG/gas No. 64/2009) taking into account the public goal of containing the inflationary pressure due to rising energy costs. Accordingly, decisions of the AEEG on these matters may limit the ability of Eni to pass an increase in the cost of the raw material onto final consumers of natural gas. Historically, the indexation mechanism set by the AEEG essentially provided that the cost of the raw material in the pricing formula to the residential sector was indexed to crude oil prices. This allowed Eni to maintain profitable operations in the retail market since selling prices mirrored supply costs.

However, following a wave of governmental measures intended to spur competition in the domestic markets, the AEEG with Resolution No. 196 effective October 1, 2013, reformulated the pricing mechanism of gas supplies to retail customers by introducing a full indexation of the raw material cost component of the tariff to spot prices. The new tariff regime intends to partially offset the negative impact to be born by wholesalers by introducing certain tariff components, applicable for the next two thermal years, in order to provide a gradual transition from oil-linked prices to spot market determined prices, to cover the costs of the transition to the new supply formula and to favor an effective renegotiation of long-term contracts for importing gas. Management believes that this development is likely to negatively affect the profitability of the Company's sales in the residential market in Italy because it is expected that trends in spot prices will be less favorable than the oil-linked cost of gas supplies to the Group, thus limiting the ability to pass cost increases to clients. This is likely to adversely affect the Company s future results and cash flow.

Antitrust and competition law

The Group s activities are subject to antitrust and competition laws and regulations in many countries of operations, especially in Europe. It is possible that the Group may incur significant loss provisions in future years relating to ongoing antitrust proceedings or new proceedings that may possibly arise. The Group is particularly exposed to this risk in its natural gas, refining and marketing and petrochemical activities due to the fact that Eni is the incumbent operator in those markets in Italy and a large European player. Furthermore, based on the findings of antitrust proceedings, plaintiffs could seek payment to compensate for any alleged damages as a result of antitrust business practices on part of Eni. Both these risks could adversely affect the Group s future results of operations and cash flows.

Environmental, health and safety regulations

Eni has incurred in the past and expects to incur significant operating expenses and expenditures in relation to compliance with applicable environmental, health and safety regulations in future years

Eni is subject to numerous EU, international, national, regional and local environmental, health and safety laws and regulations concerning its oil and gas operations, products and other activities. Generally, these laws and regulations require the acquisition of a permit before drilling for hydrocarbons may commence, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with exploration, drilling and production activities, as well as refining, petrochemical and other Group s operations, limit or prohibit drilling activities in certain protected areas, require to remove and dismantle drilling platforms and other equipment and well plug-in once oil and gas operations have terminated, provide for measures to be taken to protect the safety of the workplace and health of communities involved by the Company s activities, and impose criminal or civil liabilities for polluting the environment or harming employees or communities health and safety resulting from oil, natural gas, refining, petrochemical and other Group s operations.

These laws and regulations also regulate emissions of substances and pollutants, handling of hazardous materials and discharges to surface and subsurface of water resulting from the operation of oil and natural gas extraction and processing plants, petrochemical plants, refineries, service stations, vessels, oil carriers, pipeline systems and other facilities owned by Eni. In addition, Eni s operations are subject to laws and regulations relating to the production, handling, transportation, storage, disposal and treatment of waste materials.

Breach of environmental, health and safety laws expose the Company s employees to criminal and civil liability and the Company to the incurrence of liabilities associated with compensation for environmental, health or safety damage as well as damage to its reputation. Additionally, in the case of violation of certain rules regarding the safeguard of the environment and safety in the workplace, the Company can be liable for negligent or willful conduct on part of its employees as per Law Decree No. 231/2001.

Environmental, health and safety laws and regulations have a substantial impact on Eni s operations. Management expects that the Group will continue to incur significant amounts of operating expenses and expenditures to comply with laws and regulations addressing the safeguard of the environment, safety on the workplace, health of employees, contractors and communities involved by the Company operations, including:

- costs to prevent, control, eliminate or reduce certain types of air and water emissions and handle waste and other hazardous materials, including the costs incurred in connection with government action to address climate change;
- remedial and clean-up measures related to environmental contamination or accidents at various sites, including those owned by third parties (see discussion below);

- damage compensation claimed by individuals and entities, including local, regional or state administrations, caused by our activities or accidents; and
- costs in connection with the decommissioning and removal of drilling platforms and other facilities, and well plugging.

Furthermore, in the countries where Eni operates or expects to operate in the near future, new laws and regulations, the imposition of tougher license requirements, increasingly strict enforcement or new interpretations of existing laws and regulations or the discovery of previously unknown contamination may also cause us to incur material costs resulting from actions taken to comply with such laws and regulations, including:

- modifying operations;
- installing pollution control equipment;
- implementing additional safety measures; and
- performing site clean-ups.

As a further result of any new laws and regulations or other factors, Eni may also have to curtail, modify or cease certain operations or implement temporary shutdowns of facilities, which could diminish our productivity and materially and adversely impact our results of operations, including profits.

Security threats require continuous assessment and response measures. Acts of terrorism against our plants and offices, pipelines, transportation or computer systems could severely disrupt businesses and operations and could cause harm to people.

Existing or future laws, regulations, treaties or international agreements related to greenhouse gases and climate change could have a negative impact on our business and may result in additional compliance obligations with respect to the release, capture, and use of carbon dioxide that could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Changes in environmental requirements related to greenhouse gases and climate change may negatively impact demand for oil and natural gas exploration and production may decline as a result of environmental requirements (including land use policies responsive to environmental concerns). State, national, and international governments and agencies have been evaluating climate-related legislation and other regulatory initiatives that would restrict emissions of greenhouse gases in areas in which we conduct business. Because our business depends on the global demand for oil and natural gas, existing or future laws, regulations, treaties, or international agreements related to greenhouse gases and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on our business if such laws, regulations, treaties, or international agreements reduce the worldwide demand for oil and natural gas. Likewise, such restrictions may result in additional compliance obligations with respect to the release, capture, sequestration, and use of carbon dioxide that could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Eni has incurred in the past and may incur in the future material environmental liabilities in connection with the environmental impact of its past and present industrial activities. Also plaintiffs may seek to obtain compensation for damage resulting from events of contamination and pollution

Risks of environmental, health and safety incidences and liabilities are inherent in many of Eni s operations and products. Notwithstanding management s belief that Eni adopts high operational standards to ensure the safety of its operations and the protection of the environment and the health of people and employees, it is possible that incidents like blowouts, oil spills, contaminations and similar events could occur that would result in damage to the environment, employees and communities. The occurrence of any such events could have a material adverse impact on the Group business, competitive position, cash flow, results of operations, liquidity, future growth prospects, shareholders return and damage to the Group reputation.

We are exposed to claims under environmental requirements and, from time to time, such claims have been made against us. In Italy, environmental requirements and regulations typically impose strict liability. Strict liability means that in some situations we could be exposed to liability for clean-up and remediation costs, natural resource damages, and other damages as a result of our conduct that was lawful at the time it occurred or the conduct of prior operators or other third parties.

We are periodically notified of potential liabilities at Italian sites. These potential liabilities may arise from both historical Eni s operations and the historical operations of companies that we have acquired, including a number of industrial sites that the Company disposed of, liquidated, closed or shut down in prior years where Group products have been produced, processed, stored, distributed or sold, such as chemical plants, mineral-metallurgic plants, refineries and other facilities. At those industrial locations Eni has commenced a number of initiatives to restore and clean-up proprietary or concession areas that were allegedly contaminated and polluted by the Group s industrial activities. Notwithstanding the Group s claims that it cannot be held liable for such past contaminations (as permitted by applicable regulations in case of declaration rendered by a guiltless owner i.e. as a result of our conduct that was lawful at the time it occurred) several public administrations have been acting against Eni to claim both the environmental damages, as well as measures to perform additional clean-up and remediation projects in a number of civil and administrative proceedings. We also could be subject to third-party claims, including punitive damages, with respect to environmental matters for which we have been named as a potentially responsible party. Our exposure at these sites may be materially impacted by unforeseen adverse developments both in the final remediation costs and with respect to the final allocation among the various parties involved at the sites.

We expect remedial and clean-up activities at our sites to continue the foreseeable future impacting Eni s liquidity. As of December 31, 2013, the Group has accrued risk provisions to cope with all existing environmental liabilities whereby both a legal or constructive obligation to perform a clean-up or other remedial actions is in place and the associated costs can be reasonably estimated. The accrued amounts represent the management s best estimates of the Company s liability.

Management believes that it is possible that in the future Eni may incur significant environmental expenses and liabilities in addition to the amounts already accrued due to: (i) the likelihood of as yet unknown contamination; (ii) the results of ongoing surveys or surveys to be carried out on the environmental status of certain of Eni s industrial sites as required by the applicable regulations on contaminated sites; (iii) unfavorable developments in ongoing litigation on the environmental status of certain of the Company s site where a number of public administrations and the Italian Ministry of the Environment act as plaintiffs; (iv) the possibility that new litigation might arise; (v) the probability that new and stricter environmental laws might be implemented; and (vi) the circumstance that the extent and cost of environmental restoration and remediation programs are often inherently difficult to estimate leading to underestimation of the future costs of remediation and restoration.

As a result of those risks, liability for damages arising as a result of environmental laws could be substantial and could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Risks related to legal proceedings and compliance with anti-corruption legislation

Eni is the defendant in a number of civil actions and administrative proceedings arising in the ordinary course of business. In addition to existing provisions accrued as of December 31, 2013 to account for ongoing proceedings, it is possible that in future years Eni may incur significant losses in addition to the amounts already accrued in connection with pending legal proceedings due to: (i) uncertainty regarding the final outcome of each proceeding; (ii) the occurrence of new developments that management could not take into consideration when evaluating the likely outcome of each proceeding in order to accrue the risk provisions as of the date of the latest financial statements; (iii) the emergence of new evidence and information; and (iv) underestimation of probable future losses due to the circumstance that they are often inherently difficult to estimate.

Certain legal proceedings where Eni or its subsidiaries are parties involve the alleged breach of anti-corruptions laws and regulations and ethical misconduct. Ethical misconduct and non-compliance with applicable laws and regulations, including non-compliance with anti-bribery and anti-corruption laws, by Eni, its partners, agents or others that act on the Group s behalf, could expose Eni and its employees to criminal and civil penalties and could be damaging to Eni s reputation and shareholder value.

Risks related to changes in the price of oil, natural gas, refined products and chemicals

Operating results in Eni s Exploration & Production, Refining & Marketing and Chemical segments are affected by changes in the price of crude oil and by the impacts of movements in crude oil price on margins of refined and petrochemical products.

Eni s results of operations are affected by changes in international oil prices

Overall, lower oil prices have a net adverse impact on Eni s results of operations. The effect of lower oil prices on Eni s average realizations for produced oil is generally immediate. Furthermore, Eni s average realizations for produced oil differ from the price of Brent crude marker primarily due to the circumstance that Eni s production list, which also includes heavy crude qualities, has a lower American Petroleum Institute (API) gravity compared with Brent crude (when processed the latter allows for higher yields of valuable products compared to heavy crude qualities, hence higher market price).

The favorable impact of higher oil prices on Eni s results of operations may be offset in part by opposite trends in margins for Eni s downstream businesses

The impact of changes in crude oil prices on Eni s downstream businesses, including the Gas & Power, the Refining & Marketing and the Chemical businesses, depends upon the speed at which the prices of gas and products adjust to reflect movements in oil prices.

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In the Gas & Power segment, increases in oil price represent a risk to the profitability of the Company sales as gas supplies are mainly indexed to the cost of oil and certain refined products, while selling prices are mainly benchmarked to gas spot prices quoted at continental hubs. In the current trading environment, spot prices at those hubs have ceased to track the oil prices to which Eni s long-term supply contracts are indexed.

In addition, the AEEG and other European regulatory authorities may limit the ability of the Company to pass cost increases linked to higher oil prices onto selling prices in supplies to residential customers and small businesses as spot prices are progressively replacing oil prices in the indexation mechanism of the raw material cost in selling formulas to those customers. See the paragraph "Risks in the Company s gas business" above for more information.

In the Refining & Marketing and Chemical businesses a time lag exists between movements in oil prices and in prices of finished products.

Eni s results of operations are affected by changes in European refining margins

Results of operations of Eni s Refining & Marketing segment are substantially affected by changes in European refining margins which reflect changes in relative prices of crude oil and refined products. The prices of refined products depend on global and regional supply and demand balances, inventory levels, refinery operations, import/export balances and weather. Furthermore, Eni s realized margins are also affected by relative price movements of heavy or sour crude qualities versus light or sweet crude qualities, taking into account the ability of Eni s refineries to process complex crudes that represent a cost advantage when market prices of heavy crudes are relatively cheaper than the marker Brent price.

In each of the latest three fiscal years, Eni s refining margins were largely unprofitable as the high cost of oil was only partially transferred to final prices of fuels pressured by weak demand, high worldwide and regional inventory levels and excess refining capacity particularly in the Mediterranean Area. Furthermore, the profitability of complex cycles was impaired due to shrinking price differentials between heavy crudes versus light ones. Management does not expect any significant recovery in industry fundamentals over the short to medium term. The sector as a whole will continue to suffer from weak demand and excess capacity, while the cost of oil feedstock may continue to rise and price differentials may remain compressed.

In this context, management expects that the Company s refining margins will remain at unprofitable levels in 2014 and possibly beyond.

Eni s results of operations are affected by changes in petrochemical margins

Eni s margins on petrochemical products are affected by trends in demand for petrochemical products and movements in crude oil prices to which purchase costs of petroleum-based feedstock are indexed. Given the commoditized nature of Eni petrochemical products, it is difficult for the Company to transfer higher purchase costs for oil-based feedstock to selling prices to customers. In each of the latest three fiscal years, Eni s petrochemical business reported operating losses due to unprofitable margins on basic petrochemical products, mainly the margin on cracker, reflecting high oil-based feedstock costs and as demand for petrochemical commodities plunged due to the economic downturn. A weak demand outlook and rising oil-based feedstock costs are expected to continue to adversely affect Eni s results of operations and liquidity in this business segment in 2014 and possibly beyond.

Risks from acquisitions

Eni constantly monitors the oil and gas market in search of opportunities to acquire individual assets or companies in order to achieve its growth targets or complement its asset portfolio. Acquisitions entail an execution risk a significant risk, among other matters, that the acquirer will not be able to effectively integrate the purchased assets so as to achieve expected synergies. In addition, acquisitions entail a financial risk the risk of not being able to recover the purchase costs of acquired assets, in case a prolonged decline in the market prices of oil and natural gas occurs. Eni may also incur unanticipated costs or assume unexpected liabilities and losses in connection with companies or assets it acquires. If the integration and financial risks connected to acquisitions materialize, Eni s financial performance and shareholders returns may be adversely affected.

Risks deriving from Eni s exposure to weather conditions

Significant changes in weather conditions in Italy and in the rest of Europe from year to year may affect demand for natural gas and some refined products. In colder years, demand for such products is higher. Accordingly, the results of operations of the Gas & Power segment and, to a lesser extent, the Refining & Marketing segment, as well as the comparability of results over different periods may be affected by such changes in weather conditions. In general, the effects of climate change could result in less stable weather patterns, resulting in more severe storms and other weather conditions that could interfere with Eni s operations and damage our facilities. Furthermore, our operations, particularly offshore production of oil and natural gas, are exposed to extreme weather phenomena that can result in material disruption to our operations and consequent loss or damage of properties and facilities.

Eni s crisis management systems may be ineffective and we may be the target of cyber attacks

Eni has developed contingency plans to continue or recover operations following a disruption or incident. An inability to restore or replace critical capacity to an agreed level within an agreed time frame could prolong the impact of any disruption and could severely affect business and operations. Likewise, Eni has crisis management plans and capability to deal with emergencies at every level of its operations. If Eni does not respond or is not seen to respond in an appropriate manner to either an external or internal crisis, its business and operations could be severely disrupted.

Exposure to financial risk

Eni s business activities are inherently exposed to financial risk. This includes exposure to market risk, including commodity price risk, interest rate risk and foreign currency risk, as well as liquidity risk, and credit risk.

Eni s primary source of exposure to financial risk is the volatility in commodity prices. Generally, the Group does not hedge its strategic exposure to the commodity risk associated with its plans to find and develop oil and gas reserves, volume of gas purchased under its long-term gas purchase contracts which are not covered by contracted sales, its refining margins and other activities. The Group s risk management objectives in addressing commodity risk are to optimize the risk profile of its commercial activities by effectively managing economic margins and safeguarding the value of Eni assets. To achieve this, Eni engages in risk management activities seeking both to hedge Group s exposures and to profit from short-term market opportunities and trading. The Group s risk management has evolved particularly in response to the deep changes occurred in the competitive landscape of the gas marketing business, gas volatile margins and development of liquid gas spot markets.

Eni is engaged in substantial trading and commercial activities in the physical markets. Eni also uses financial instruments such as futures, options, over the counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity in order to manage the commodity risk exposure. Eni also uses financial instruments to manage foreign exchange and interest rate risk.

The Group s approach to risk management includes identifying, evaluating and managing the financial risk using a top-down approach whereby the Board of Directors is responsible for establishing the Group risk management strategy and setting the maximum tolerable amounts of risk exposure. The Group s Chief Executive Officer is responsible for implementing the Group risk management strategy, while the Group s Chief Financial Officer is in charge of defining policies and tools to manage the Group s exposure to financial risk, as well as monitoring and reporting activities. Various Group committees are in charge of defining internal criteria, guidelines and targets of risk management activities consistent with the strategy and limits defined at Eni s top level, to be used by the Group s business units, including monitoring and controlling activities. Although Eni believes it has established sound risk management procedures, trading activities involve elements of forecasting and Eni is exposed to the risks of market movements, of incurring significant losses if prices develop contrary to management expectations and of default of counterparties.

Commodity risk

Commodity risk is the risk associated with fluctuations in the price of commodities which may impact the Group s results of operations and cash flow. Exposure to commodity risk is both of a strategic and commercial nature. Generally, the Group does not hedge its strategic exposure to commodity risk. On the other hand, the Group actively manages its exposure to commercial risk which arises when a contractual sale of a commodity has occurred or it is highly probable that it will occur and the Group aims to lock in the associated commercial margin.

The Group s risk management policies have evolved particularly in response to the deep changes occurred in the competitive landscape of the gas marketing business, volatile gas margins and development of liquid markets to trade spot gas. These policies also contemplate the use of derivative contracts for speculative purposes whereby Eni is seeking to profit from opportunities available in the gas market based, among other things, on its expectations regarding future prices.

As part of those trading activities, the Company is implementing strategies of asset-backed trading in order to maximize the economic value of the flexibilities associated with its assets. Management believes that the price risks related to asset-backed trading activities are mitigated by the natural hedge granted by the assets availability.

These derivative contracts entered into for trading purposes may lead to gains as well as losses, which, in each case, may be significant. Those derivatives are accounted for through profit and loss, resulting in higher volatility in Eni s earnings.

Exchange rate risk

Movements in the exchange rate of the euro against the U.S. dollar can have a material impact on Eni s results of operations. Prices of oil, natural gas and refined products generally are denominated in, or linked to, U.S. dollars, while a significant portion of Eni s expenses are denominated in euros. Similarly, prices of Eni s petrochemical products are generally denominated in, or linked to, the euro, whereas expenses in the Chemical segment are denominated both in euros and U.S. dollars. Accordingly, a depreciation of the U.S. dollar against the euro generally has an adverse impact on Eni s results of operations and liquidity because it reduces booked revenues by an amount greater than the decrease in U.S. dollar-denominated expenses and may also result in significant translation adjustments that impact Eni s shareholders equity. The Exploration & Production segment is particularly affected by movements in the U.S. dollar versus the euro exchange rates as the U.S. dollar is the functional currency of a large part of its foreign subsidiaries and therefore movements in the U.S. dollar versus the euro exchange rate affect year-on-year comparability of results of operations. In 2013, the Exploration & Production results of operations were adversely affected by an appreciation of 3.3% of the euro against the U.S. dollar determining a lower booked operating profit when translating the dollar denominated profit of Eni s upstream subsidiaries into the Group presentation currency which is the euro.

Susceptibility to variations in sovereign rating risk

Eni s credit ratings are potentially exposed to risk in reductions of sovereign credit rating of Italy. On the basis of the methodologies used by Standard & Poor s and Moody s, a potential downgrade of Italy s credit rating may have a potential knock-on effect on the credit rating of Italian issuers such as Eni and make it more likely that the credit rating of the Notes or other debt instruments issued by the Company could be downgraded.

Interest rate risk

Interest on Eni s debt is primarily indexed at a spread to benchmark rates such as the Europe Interbank Offered Rate, "Euribor", and the London Interbank Offered Rate, "Libor". As a consequence, movements in interest rates can have a material impact on Eni s finance expense in respect to its debt. Additionally, spreads offered to the Company may rise in connection with variations in sovereign rating risks or company rating risks, as well as the general conditions of capital markets.

Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the Group may not be available, or the Group is unable to sell its assets on the marketplace in order to meet short-term financial requirements and to settle obligations. Such a situation would negatively impact the Group results of operations and cash flows as it would result in Eni incurring higher borrowing expenses to meet its obligations or, under the worst conditions, the inability of Eni to continue as a going concern. European and global financial markets are currently subject to volatility amid concerns over the European sovereign debt crisis and weak macroeconomic growth, particularly in the Euro-zone. If there are extended periods of constraints in the financial markets, or if Eni is unable to access the financial markets (including cases where this is due to our financial position or market sentiment as to our prospects) at a time when cash flows from our business operations may be under pressure, our ability to maintain our long-term investment program may be impacted with a consequent effect on our growth rate, and may impact shareholder returns, including dividends or share price.

Credit risk

Credit risk is the potential exposure of the Group to losses in case counterparties fail to perform or pay due amounts. Credit risks arise from both commercial partners and financial ones. In the last couple of years, the Group has experienced a higher than normal level of counterparty failure due to the severity of the economic and financial downturn and has recorded a significant increase in the amount of trade receivables due at the balance sheet date. In Eni s 2013 Consolidated Financial Statements, Eni accrued an allowance against doubtful accounts amounting to euro 384 million, mainly relating to the Gas & Power business. Management believes that this business is particularly exposed to credit risks due to its large and diversified customer base which include a large number of medium and small sized businesses and retail customers who have been particularly impacted by the financial and economic downturn. However, trade receivable amounts due at the balance sheet date have also increased in relation to supplies of the Group products to state-owned companies, public administrations and other governmental agencies in Italy and abroad also in the Exploration & Production segment. We believe that the credit risk represents an issue to the Company which will require management focus and commitment going forward.

Critical accounting estimates

The preparation of the Consolidated Financial Statements requires the use of estimates and assumptions that affect the assets, liabilities, revenues and expenses reported in the financial statements, as well as amounts included in the notes thereto, including discussion and disclosure of contingent liabilities. Estimates made are based on complex or subjective judgments and past experience and other assumptions deemed reasonable in consideration of the information available at the time. The accounting policies and areas that require the most significant judgments and estimates to be used in the preparation of the Consolidated Financial Statements are in relation to the accounting for oil and natural gas activities, specifically the determination of proved and proved developed reserves, impairment of fixed assets, intangible assets and goodwill, asset retirement obligations, business combinations, pensions and other post-retirement benefits, recognition of environmental liabilities and other risk provisions, and recognition of revenues in the oilfield services construction and engineering businesses. Although management believes these estimates to represent the best outcome of the estimation process, actual results could differ from such estimates, due to, among other things, the following factors: uncertainty, lack or limited availability of information, availability of new informative elements, variations in economic conditions such as prices, costs, other significant factors including evolution in technologies, industrial practices and standards (e.g. removal technologies) and the final outcome of legal, environmental or regulatory proceedings.

Digital infrastructure is an important part of maintaining our operations, and a breach of our digital security could result in serious damage to business operations, personal injury, damage to assets, harm to the environment, breaches of regulations, litigation, legal liabilities and reparation costs

The reliability and security of our digital infrastructure is critical to maintaining the availability of our business applications, including the reliable operation of technology in our various business operations and the collection and processing of financial and operational data, as well as the confidentiality of certain third-party information. If our systems for protecting our digital security prove not to be sufficient, either due to intentional actions such as cyber attacks or due to negligence, we could be adversely affected by, among other things, loss or damage of intellectual property, proprietary information, or customer data, having our business operations interrupted, and increased costs to prevent, respond to, or mitigate potential risks to our digital infrastructure; also, in some circumstances, failures to protect digital infrastructure could result in injury to people, damage to assets, harm to the environment, breaches of regulations, litigation, legal liabilities and reparation costs.

The Company s auditors, like all other independent registered public accounting firms operating in Italy, are not permitted to be subject to inspection by the Public Company Accounting Oversight Board, and accordingly, investors may be deprived of the benefits of such inspection

The independent registered public accounting firm that issues the audit reports included in our annual reports filed with the U.S. Securities and Exchange Commission (the U.S. SEC), as auditor of companies that are traded publicly in the United States and firms registered with the Public Company Accounting Oversight Board, or PCAOB, is required by the laws of the United States to undergo regular inspections by the PCAOB to assess its compliance with U.S. SEC rules and PCAOB professional standards.

Because our auditor is a registered public accounting firm in Italy, a jurisdiction where the PCAOB is currently unable under Italian law to conduct inspections pending the mutual agreement between the PCAOB and the Italian Authorities, our auditor, like all other independent registered public accounting firms in Italy, is currently not inspected by the PCAOB. Inspections of audit firms that the PCAOB has conducted where allowed have identified deficiencies in those firms audit procedures and quality control procedures, which may be addressed as part of the inspection process to improve future audit quality. The lack of PCAOB inspections in Italy prevents the PCAOB from regularly evaluating our auditor s audits and quality control procedures. As a result, the inability of the PCAOB to conduct inspections of auditors in Italy may deprive investors of the benefits of PCAOB inspections.

Item 4. INFORMATION ON THE COMPANY

History and development of the Company

Eni SpA with its consolidated subsidiaries engages in the oil and gas exploration and production, marketing of gas and LNG, refining and marketing of petroleum products, power generation, production and marketing of petrochemical products, commodity trading and oilfield services and engineering industries. Eni has operations in 85 countries and 83,887 employees as of December 31, 2013.

Eni, the former Ente Nazionale Idrocarburi, a public law agency, established by Law No. 136 of February 10, 1953, was transformed into a joint stock company by Law Decree No. 333 published in the Official Gazette of the Republic of Italy No. 162 of July 11, 1992 (converted into law on August 8, 1992, by Law No. 359, published in the Official Gazette of the Republic of Italy No. 190 of August 13, 1992). The Shareholders Meeting of August 7, 1992 resolved that the company be called Eni SpA. Eni is registered at the Companies Register of Rome, register tax identification number 00484960588, R.E.A. Rome No. 756453. Eni is expected to remain in existence until December 31, 2100; its duration can however be extended by resolution of the shareholders.

Eni s registered head office is located at Piazzale Enrico Mattei 1, Rome, Italy (telephone number: +39-0659821). Eni branches are located in:
San Donato Milanese (Milan), Via Emilia, 1; and
San Donato Milanese (Milan), Piazza Ezio Vanoni, 1.

Internet address: eni.com
The name of the agent of Eni in the United States is Stefano Lucchini, 485 Madison Avenue, New York, NY 10002.

Eni s principal segments of operations are described below.

Eni s Exploration & Production segment engages in oil and natural gas exploration and field development and production, as well as LNG operations in 42 countries, including Italy, Libya, Egypt, Norway, the United Kingdom, Angola, Congo, Nigeria, the United States, Kazakhstan, Russia, Algeria, Australia, Venezuela, Iraq and Mozambique. In 2013, Eni average daily production amounted to 1,537 KBOE/d on an available-for-sale basis. As of December 31, 2013, Eni s total proved reserves amounted to 6,535 mmBOE; proved reserves of subsidiaries totaled 5,708 mmBOE; Eni s share of reserves of equity-accounted entities was 827 mmBOE. In 2013, Eni s Exploration & Production segment reported net sales from operations (including inter-segment sales) of euro 31,264 million and operating profit of euro 14,868 million.

Eni s Gas & Power segment engages in supply, trading and marketing of gas and electricity, international gas transport activities, and LNG supply and marketing. This segment also includes the activity of electricity generation that is ancillary to the marketing of electricity. In 2013, Eni s worldwide sales of natural gas amounted to 93.17 BCM. Sales in Italy amounted to 35.86 BCM, while sales in European markets were 47.35 BCM that included 4.67 BCM of gas sold to certain importers to Italy. Eni produces power at a number of operated sites in Italy with a total installed capacity of 5.3 GW as of December 31, 2013. In 2013, sales of power totaled 35.05 TWh. In 2013, Eni s Gas & Power segment reported net sales from operations (including inter-segment sales) of euro 32,212 million and operating loss of euro 2,967 million.

Eni s Refining & Marketing segment engages in crude oil supply and refining and marketing of petroleum products at retail and wholesale markets mainly in Italy and in the rest of Europe. In 2013, processed volumes of crude oil and other feedstock amounted to 27.38 mmtonnes and sales of refined products were 43.49 mmtonnes, of which 23.34

mmtonnes in Italy. Retail sales of refined products at Eni s service stations amounted to 9.69 mmtonnes in Italy and in the rest of Europe. In 2013, Eni s retail market share in Italy through its "Eni" and "Agip" branded network of service stations was 27.5%. In 2013, Eni s Refining & Marketing segment reported net sales from operations (including inter-segment sales) of euro 57,238 million and operating loss of euro 1,492 million.

Eni also engages in commodity risk management and asset-backed trading activities. Through the trading department of the parent company and its wholly-owned subsidiary Eni Trading & Shipping SpA, the Group engages in derivative activities targeting the full spectrum of energy commodities on both the physical and financial trading venues. The objective of this activity is both to hedge part of the Group exposure to the commodity risk and to optimize commercial margins by entering speculative derivative transactions. Eni Trading & Shipping SpA and its subsidiaries also provide Group companies with crude oil and products supply, trading and shipping services. The results of the activity of commodity risk management and other services are reported within the Gas & Power segment with regard to the results on commodity risk management activities relating to gas and electricity; while the portion of results which pertains to oil and products trading derivatives and supply and shipping services are reported within the Refining & Marketing segment.

Eni s chemical activities include production of olefins and aromatics, basic intermediate products, polyethylene, polystyrenes, and elastomers. Eni s chemical operations are concentrated in Italy and Western Europe. In 2013, Eni sold 3.79 mmtonnes of chemical products. In 2013, Eni s Chemical segment reported net sales from operations (including inter-segment sales) of euro 5,859 million and operating loss of euro 725 million.

Eni engages in oilfield services, construction and engineering activities through its partially-owned subsidiary Saipem and Saipem s controlled entities (Eni s interest being 42.91%). Saipem provides a full range of engineering, drilling and construction services to the oil and gas industry and downstream refining and petrochemical sectors, mainly in the field of performing large EPC contracts offshore and onshore for the construction and installation of fixed platforms, sub-sea pipe laying and floating production systems and onshore industrial complexes. In 2013, Eni s Engineering & Construction segment reported net sales from operations (including intragroup sales) of euro 11,598 million and operating loss of euro 98 million.

A list of Eni s subsidiaries is included as an exhibit to this Annual Report on Form 20-F.

Strategy

Our strategy is to grow our oil and gas production business, which is characterized by improving returns and to restructure our less profitable Europe-based businesses in the marketing of gas and in the production and marketing of refined products and chemical products in order to increase the cash flows deriving from our businesses. Our planning assumptions do not contemplate any improvement in the fundamentals of the European industries of gas, refining and petrochemicals which will continue to be adversely affected by weak demand, overcapacity and oversupplies, strong competition and other cost disadvantages. As a part of our strategy, we are also planning to restore the profitability of our listed subsidiary Saipem, which in 2013 was impacted by activity downturn and extraordinary contract losses. We expected that the planned improvements in the cash flows generated by operating activities coupled with the continuation of our ongoing disposal program will enable us to increase cash disbursements to shareholders by means of a progressive dividend policy and under certain conditions, through share repurchase programs. See "Item 5 Management s expectations of operations".

In the Exploration & Production segment we plan to grow profitably oil and gas production and to fully replace produced reserves thanks to a continuing focus on exploration activities and execution. Exploration will remain one of the main drivers of our long-term growth and cost position and we expect continuing exploration success at competitive costs. In the next four years, we intend to boost returns by starting up production in new projects with higher net profit per BOE than our current average, provided that we are able to deliver on time and on budget. To this end we plan to carefully select our investment projects by better phasing our long-plateau projects, to retain strong control and coordination of certain critical project activities such as engineering, construction and commissioning and finally to increase the share of operated production in our portfolio. Project operatorship enables us to better schedule and control project execution, expenditures and timely achievement of project milestones. In addition, we plan to seek cost efficiencies through greater deployment of proprietary technologies designed to maximize the rate of hydrocarbon recovery from reservoirs, the reduction of drilling costs and ongoing operational improvement. This strategy will be underpinned by continuing risk mitigation as we are exposed to political risks and operational risks relating to increasingly high complexity of our projects and environmental challenges. See "Item 3 Risk factors Risks associated with the exploration and production of oil and natural gas";

In the Gas & Power segment we are seeking to restore profitability and improve cash flows against the backdrop of structural headwinds in the European gas sector where we do not expect significant improvement in the trading environment due to continued weak demand, strong competition and oversupplies which will affect sale prices and margins. Our turnaround strategy will be driven by the renegotiation of our entire portfolio of long-term supply contracts in order to align our cost position to prevailing market conditions and to mitigate the take-or-pay risk to our liquidity as we manage through the downturn. The return to profitability will be helped by focusing on value-added segments, developing LNG sales in international markets and optimizing margins by means of our trading activities. Finally, we will speed up our restructuring efforts by streamlining operations, rationalizing logistics and cutting general, administrative and other fixed expenses;

Our priority in the Refining & Marketing segment is to restore profitability against the backdrop of weak industry fundamentals and an unfavorable trading environment. We plan to further reduce and restructure refining capacity and to implement a number of efficiency and cost reduction initiatives, energy saving and optimization of plant operations, in order to drive margin expansions. Management plans to improve plant flexibility and process integration, to make selective capital projects for upgrading refinery complexity and the safety and reliability of our assets. In the marketing business in Italy we plan to enhance profitability by closing down marginal outlets and continuing upgrading our modern and most efficient service stations, also improving service quality and client retention and non-oil profit contribution taking into account a weak outlook for fuel consumption. Outside Italy, Eni plans to grow selectively in target European markets and divest marginal assets;

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Our Engineering & Construction segment is expected to return to profitability after a challenging 2013 which was severely hit by worsening trading environment, as well as customer relationship and management issues. In 2013, management undertook business reorganization, refocused the operations and implemented a more selective marketing strategy. The outlook for 2014 is uncertain as an expected return to profitability depends on the speed at which new orders are acquired and the effective execution of contracts underway. Management believes that the business remains well positioned to restore revenue and profitability growth in the medium term leveraging on our technologically-advanced assets and our skills in engineering and project management and execution of large and complex oil and gas developments; and

In the Chemical segment, we plan to recover profitability by progressively reducing the exposure to loss making commodity chemicals while at the same time developing innovative and niche productions. We intend to grow the green chemistry business leveraging on current projects to establish joint ventures with operators in the bio-technologies industry. We believe that bio-technologies can be profitably used in the production of innovative chemical products replacing the mature oil-based technologies. We also plan to expand our elastomers and other niche productions internationally to seek to capture opportunities for growth and returns in the fast-growing Asian markets leveraging our technologies and know-how in those fields.

In executing this strategy, management intends to pursue integration opportunities among segments and within each segment to strongly focus on efficiency improvement through technology upgrading, cost efficiencies, commercial and supply optimization and continuing process streamlining across all segments. Over the next four years, Eni plans to execute capital expenditure for euro 54 billion to support continuing organic growth in its segments, in particular in the Exploration & Production which will absorb 83% of planned expenditures. In this amount are included funds to finance joint venture projects and associates.

For the full year 2014, management expects a capital budget in line with 2013 (in 2013 capital expenditure amounted to euro 12.8 billion, while expenditures incurred in joint venture initiatives and other investments amounted to euro 0.32 billion).

Eni plans to focus on preserving a balanced and well-established financial structure. Management seeks to maintain the ratio of net borrowings to total equity within a target range of 0.1-0.3 under the assumption of a Brent price scenario of 104 $/BBL in 2014 which will progressively decline in the subsequent years to our long-term case of 90 $/BBL from 2017 onwards and other trading assumptions, as well as the commitments of funding capital expenditure plans and implementing the Company s progressive dividend policy and share repurchases (see "Item 5 Operating and financial review and prospects Management s expectations of operations" and "Item 3 Risk factors").

For fiscal year 2013, management plans to distribute a dividend of euro 1.10 per share subject to approval from the General Shareholders Meeting scheduled on May 8, 2014; the 2013 dividend represents a 2% increase from the previous year.

Further details on each business segment strategy are discussed throughout this item. For a description of risks and uncertainties associated with the Company s outlook, and the capital expenditure program see "Item 5 Operating and financial review and prospects Management s expectations of operations".

In the next four-year period, Eni plans to make expenditures dedicated to technological research and innovation activities amounting to euro 1.1 billion. Management believes that technological developments may secure long-term competitive advantages to the Company. For more information on Research and development activity see page 83.

Significant business and portfolio developments

The significant business and portfolio developments that occurred in 2013 and to date in 2014 were the following:

On July 26, 2013, Eni finalized the sale of a 28.57% interest in Eni East Africa (EEA) to China National Petroleum Corp (CNPC). EEA retains a 70% interest in the Area 4 mineral property, located offshore of Mozambique where we made a large gas discovery that we are currently appraising. CNPC has acquired, through its equity investment in EEA, a 20% interest in Area 4, while Eni retains operatorship and a 50% interest through the remaining stake in the investee. The total consideration for the sale was equal to euro 3,386 million, with a gain recorded in profit and loss account (euro 3,359 million, euro 2,994 million net of tax charges).

On January 15, 2014, Eni sold to certain Gazprom subsidiaries its 60% interest in Artic Russia which is the parent company with a 49% stake of Severenergia, which holds four licenses for the exploration and production of hydrocarbons in the Region of Yamal Nenets (Siberia), including in particular the on-stream field of Samburgskoye, Eni s first development in the Russian upstream. The cash consideration for the disposal amounted to euro 2.16 billion ($2,940 million). Eni s interest in Artic Russia was classified as an asset held-for-sale and measured at fair value, after joint control was lost over the investee following the satisfaction, before year end, of all conditions precedent to the Sale and Purchase Agreement signed with

Gazprom in November 2013. This resulted in a revaluation gain of euro 1,682 million recorded to profit and loss. The consideration for the disposal was received in January 2014.

On March 31, 2014, Eni and Statoil have signed final agreement on the revision of the long-term gas supply contract currently in force between the two parties. The revision is reflecting changed fundamentals in the gas sector and will determine a positive effect in 2014 profit. The final agreement, which follows the Heads of Agreement signed on February 27, 2014, implies the end of the arbitration proceedings previously initiated by Eni.

On March 28, 2014, through an accelerated book-building procedure aimed at institutional investors, Eni sold approximately 7% of the share capital of Galp Energia SGPS SA at the price of euro 12.10 per share, for a total consideration of euro 702.4 million. Following this transaction, Eni retains a 9% interest in Galp, of which 8% underlying the approximately euro 1,028 million exchangeable bond due on November 30, 2015.

On November 5, 2013, Eni signed an agreement with the American company Quicksilver to conduct exploration and development activities in an area with unconventional oil reservoirs (shale oil), onshore the United States. Eni is expected to acquire a 50% interest in the Leon Valley area (West Texas). The work plan provides for the drilling of up to five exploration wells, aiming at determining the hydrocarbon potential of the area and the subsequent development plan. Eni will invest up to $52 million, for the completion of the project s exploration activities. The agreement also establishes that Eni will obtain 50% of another area located in the Leon Valley, without additional costs.

On September 11, 2013, following the completion, test and delivery of all infrastructures, the first oil from the giant Kashagan field was produced. From October 2013 production has been halted due to a technical issue that occurred to the pipeline transporting acid gas from offshore to onshore facilities, without any impact on the environment and local communities. Recovery activities are ongoing. Management believes that from 2015 field production will recover to the originally expected level and the field contribution to Eni s production profile for the year 2014 has been prudently assumed to be marginal.

The exploration campaign carried out in 2013 in the operated Area 4 offshore the Rovuma Basin in Mozambique resulted in the appraisal of the Mamba and Coral discoveries and a new prospect in the Southern section of Area 4, where in September 2013 Eni made the Agulha discovery. Management estimates that Area 4 may contain significant amounts of gas resources. Agulha was drilled in 2,492 meters of water and reached a total depth of 6,203 meters. In 2014, Eni will continue appraisal activities, particularly regarding the new exploration prospect, where the drilling of two to three additional wells is planned.

On June 21, 2013, Eni and Rosneft signed a strategic cooperation agreement for exploration activities in the Russian section of the Barents Sea (Fedynsky and Central Barents licenses) where seismic surveys have been started, and in the Black Sea (Western Chernomorsky license).

In 2013, Eni s chemical subsidiary Versalis progressed in the process of expansion in the growing Southeast Asian markets, by establishing a joint venture with the South Korean company Lotte Chemical and by signing a shareholder agreement with Malaysian company Petronas. The agreements cover the production and marketing of polymers and elastomers in the Asian markets.

In addition, Eni closed the following transactions:

In September 2013, Eni acquired the Ngolo exploration Block, which is part of the Cuvette Basin. Eni will operate an exploration joint venture that will be established with the Congolese state company Société Nationale des Pétroles du Congo (SNPC). Exploration activities will take place over a period of 10 years. Management believes that the Cuvette Basin is one of the new themes of frontier exploration in Africa.

In 2013, Eni was awarded the operatorship of the PL 717, PL 712 and PL 716 licenses, with an interest of 40%, as well as an interest of 65% in the PL 697 license and the interest of 30% in the PL 696 and 714 licenses.

In April 2013, Eni was awarded an exploration license (Production Sharing Contract) covering an area of 662 square kilometers in the Timor Sea, within the Joint Petroleum Development Area (JPDA), which is administered by both Australia and Timor Leste. The PSC foresees the commitment to drill two exploration wells during the first two years and options for other two wells.

In January 2013, Eni signed exploration and production sharing contracts with the relevant authorities of the Republic of Cyprus, for Blocks 2, 3 and 9 located in the Cypriot deep offshore portion of the Levantine Basin over an area of around 12,530 square kilometers, thus marking Eni s entry into the Country.

Eni was awarded a deepwater exploration block (Block 9) in the EGAS 2012 international bidding round, located in the Eastern Mediterranean offshore Egypt.

In 2013, capital expenditures of continuing operations amounted to euro 12,800 million, of which 89% related to Exploration & Production, Gas & Power and Refining & Marketing segments, and primarily related to:
(i) development of oil and gas reserves (euro 8,580 million) deployed mainly in Norway, the United States, Angola, Congo, Italy, Nigeria, Kazakhstan, Egypt and the United Kingdom, and exploration projects (euro 1,669 million) carried out mainly in Mozambique, Norway, Congo, Togo, Nigeria, the United States and Angola; (ii) upgrading of the fleet used in the Engineering & Construction segment (euro 902 million); (iii) refining, supply and logistics in Italy and outside Italy (euro 462 million) with projects designed to improve the conversion rate and flexibility of refineries, in particular at the Sannazzaro refinery, as well as the upgrade of the refined product retail network in Italy and in the rest of Europe (euro 210 million); and (iv) initiatives to improve flexibility of the combined-cycle power plants (euro 119 million). There were no significant acquisitions in the year.

In 2012, capital expenditures of continuing operations amounted to euro 12,805 million, of which 89% related to Exploration & Production, Gas & Power and Refining & Marketing segments, and primarily related to:
(i) development of oil and gas reserves (euro 8,304 million) deployed mainly in Norway, the United States, Congo, Italy, Kazakhstan, Angola and Algeria, and exploration projects (euro 1,850 million) carried out mainly in Mozambique, Liberia, Ghana, Indonesia, Nigeria, Angola and Australia; (ii) upgrading of the fleet used in the Engineering & Construction segment (euro 1,011 million); (iii) refining, supply and logistics with projects designed to improve the conversion rate and flexibility of refineries (euro 639 million), in particular at the Sannazzaro refinery, as well as upgrading and rebranding of the refined product retail network (euro 259 million); and (iv) initiatives to improve flexibility of the combined-cycle power plants (euro 123 million). There were no significant acquisitions in the year.

In 2011, capital expenditures of continuing operations amounted to euro 11,909 million, of which 88% related to Exploration & Production, Gas & Power and Refining & Marketing segments, and primarily regarded: (i) the development of oil and gas reserves (euro 7,357 million) deployed mainly in Norway, Kazakhstan, Algeria, the United States, Congo and Egypt, and exploration projects (euro 1,210 million) carried out mainly in Australia, Angola, Mozambique, Indonesia, Ghana, Egypt, Nigeria and Norway; (ii) the upgrading of the fleet used in the Engineering & Construction segment (euro 1,090 million); and (iii) projects aimed at improving the conversion capacity and flexibility of refineries, and at building and upgrading service stations in Italy and outside Italy (totaling euro 629 million). There were no significant acquisitions in the year.

BUSINESS OVERVIEW

Exploration & Production

Eni s Exploration & Production segment engages in oil and natural gas exploration and field development and production, as well as LNG operations, in 42 countries, including Italy, Libya, Egypt, Norway, the United Kingdom, Angola, Congo, Nigeria, the United States, Kazakhstan, Russia, Algeria, Australia, Venezuela, Iraq and Mozambique. In 2013, Eni average daily production amounted to 1,537 KBOE/d on an available-for-sale basis. As of December 31, 2013, Eni s total proved reserves amounted to 6,535 mmBOE; proved reserves of subsidiaries totaled 5,708 mmBOE; Eni s share of reserves of equity-accounted entities stood to 827 mmBOE.

Eni s strategy in its Exploration & Production operations is to pursue profitable production growth by developing its portfolio of projects underway and the exploration discoveries which the Company is currently appraising and by optimizing its producing fields. We plan to achieve a production growth rate of 3% on average in the next 2014-2017 four-year period, based on an expectation of a gradual decrease in oil prices from 104 $/BBL in 2014 to 90 $/BBL in 2017 and certain other trading environment assumptions including an indication of Eni s production volume sensitivity to oil prices which are disclosed under Item 5 Management s expectations of operations . Following disruptions in Libya and Nigeria which were affected by geopolitical factors throughout 2013, management prudently assumed the contribution of these important countries to Eni s production growth profile to be marginal up to 2015.

Management plans to achieve the target production growth by continuing development activities and new project start-ups in the main areas of operations including, Sub-Saharan Africa, Venezuela, Barents Sea, Kazakhstan and the Far East, leveraging Eni s vast knowledge of reservoirs and geological basins, as well as technical and producing synergies. We plan to start 26 new large fields over the next four years which will contribute an estimated 500

KBOE/d of new production by 2017; about 70% of these new projects have already been sanctioned and the management plans to sanction almost all by the end of 2014.

Management plans to maximize the production recovery rate at our current fields by counteracting natural field depletion and reducing facilities downtime. This will require intense development activities of work-over and infilling. We expect that continuing technological innovation and competence build-up will drive increasing rates of reserve recovery.

Management plans to invest euro 38 billion to develop reserves over the next four years. An important share of these expenditures will be allocated to certain development projects which will support the Company s long-term production plateau, particularly we plan to start developing the recent gas discovery offshore Mozambique and to progress large and complex projects in Congo, Indonesia, Venezuela, Nigeria, Norway and Kazakhstan which will support our long-term growth. We are also planning to maintain a prevailing share of projects regulated by production sharing agreement in our portfolio; this will shorten the cost recovery in an environment of high crude oil prices.

Exploration projects will attract some euro 5.6 billion to appraise the latest discoveries made by the Company, to explore new plays and to support continuing reserve replacement over the next four years. 60% of investments will be in lower risk environments such as proven and near field areas.

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The most important amounts of exploration expenses will be incurred in Angola, Congo, the United States, Nigeria, Egypt, Norway and Indonesia; important resources will be dedicated to explore new areas, including Kenya, Vietnam, Cyprus, the Russian sections of the Barents Sea and the Black Sea and the pre-salt layers offshore West Africa. Management plans to achieve a balance between exploration projects in conventional fields versus projects in high risk/high reward basins.

Management intends to implement a number of initiatives to support profitability in its upstream operations by exercising tight control on project time schedules and costs and reducing the time span which is necessary to develop and market reserves. We acknowledge that our results of operations and production levels for the year have been adversely impacted by delays and cost overruns at a number of projects. We plan to mitigate those risks in the future by: (i) in-sourcing critical engineering and project management activities also redeploying to other areas key competences which will be freed with the start-up of certain strategic projects and increase direct control and governance on construction and commissioning activities; and (ii) signing framework agreements with major suppliers, using standardized specifications to speed up pre-award process for critical equipment and plants, increasing focus on supply chain programming to optimize order flows. Based on these initiatives we believe that almost all of our projects which we are currently developing over the next four-year plan will be completed on time and on cost schedule.

We expect that costs to develop and operate fields will increase in the next years due to sector-specific inflation, and growing complexity of new projects. We plan to counteract those cost increases by leveraging on cost efficiencies associated with: (i) increasing the scale of our operations as we concentrate our resources on larger fields than in the past where we plan to achieve economies of scale; (ii) expanding projects where we serve as operator. We believe operatorship will enable the Company to exercise better cost control, effectively manage reservoir and production operations, and deploy our safety standards and procedures to minimize risks; and (iii) applying our technologies which we believe can reduce drilling and completion costs.

We plan to mitigate the operational risk relating to drilling activities by applying Eni s rigorous procedures throughout the engineering and execution stages, by leveraging on proprietary drilling technologies, excellent skills and know-how, increased control of operations and by deploying technologies which we believe to be able to reduce blowout risks and to enable the Company to respond quickly and effectively in case of emergencies.

Eni will pursue further growth options by developing unconventional plays, gas-to-LNG projects and integrated gas projects. Finally, we intend to optimize our portfolio of development properties by focusing on areas where our presence is well established, and divesting non-strategic or marginal assets.

For the year 2014, management plans to spend over euro 11 billion in reserves development and exploration projects.

Disclosure of reserves

Overview

The Company has adopted comprehensive classification criteria for the estimate of proved, proved developed and proved undeveloped oil and gas reserves in accordance with applicable U.S. Securities and Exchange Commission regulations, as provided for in Regulation S-X, Rule 4-10. Proved oil and gas reserves are those quantities of liquids (including condensates and natural gas liquids) and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

Oil and natural gas prices used in the estimate of proved reserves are obtained from the official survey published by Platt s Marketwire, except when their calculation derives from existing contractual conditions. Prices are calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. Prices include consideration of changes in existing prices provided only by contractual arrangements.

Engineering estimates of the Company s oil and gas reserves are inherently uncertain. Although authoritative guidelines exist regarding engineering criteria that have to be met before estimated oil and gas reserves can be designated as "proved", the accuracy of any reserves estimate is a function of the quality of available data and engineering and geological interpretation and evaluation. Consequently, the estimated proved reserves of oil and natural gas may be subject to future revision and upward and downward revisions may be made to the initial booking of reserves due to analysis of new information.

Proved reserves to which Eni is entitled under concession contracts are determined by applying Eni s share of production to total proved reserves of the contractual area, in respect of the duration of the relevant mineral right.

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Proved reserves to which Eni is entitled under production sharing agreements are calculated so that the sale of production entitlements should cover expenses incurred by the Group to develop a field (cost oil) and recognize the profit oil set contractually (profit oil). A similar scheme applies to buy-back and service contracts.

Reserves governance

Eni retains rigorous control over the process of booking proved reserves, through a centralized model of reserves governance. The Reserves Department of the Exploration & Production Division is entrusted with the task of: (i) ensuring the periodic certification process of proved reserves; (ii) continuously updating the Company s guidelines on reserves evaluation and classification and the internal procedures; and (iii) providing training of staff involved in the process of reserves estimation.

Company guidelines have been reviewed by DeGolyer and MacNaughton (D&M), an independent petroleum engineering company, which has stated that those guidelines comply with the U.S. SEC rules[1]. D&M has also stated that the Company guidelines provide reasonable interpretation of facts and circumstances in line with generally accepted practices in the industry whenever U.S. SEC rules may be less precise. When participating in exploration and production activities operated by other entities, Eni estimates its share of proved reserves on the basis of the above guidelines.

The process for estimating reserves, as described in the internal procedure, involves the following roles and responsibilities: (i) the Business Unit Managers (geographic units) and Local Reserves Evaluators (LRE) are in charge with estimating and classifying gross reserves including assessing production profiles, capital expenditure, operating expenses and costs related to asset retirement obligations; (ii) the Petroleum Engineering Department at the head office verifies the production profiles of such properties where significant changes have occurred; (iii) Geographic Area Managers verify the commercial conditions and the progress of the projects; (iv) the Planning and Control Department provides the economic evaluation of reserves; and (v) the Reserves Department, through the Division Reserves Evaluators (DRE), provides independent reviews of fairness and correctness of classifications carried out by the above mentioned units and aggregates worldwide reserves data.

The head of the Reserves Department attended the "Politecnico di Torino" and received a Master of Science degree in Mining Engineering in 1985. She has more than 25 years of experience in the oil and gas industry and more than 15 years of experience in evaluating reserves.

Staff involved in the reserves evaluation process fulfils the professional qualifications requested and maintains the highest level of independence, objectivity and confidentiality in accordance with professional ethics. Reserves Evaluators qualifications comply with international standards defined by the Society of Petroleum Engineers.

Reserves independent evaluation

Since 1991, Eni has requested qualified independent oil engineering companies to carry out an independent evaluation[2] of part of its proved reserves on a rotational basis. The description of qualifications of the persons primarily responsible for the reserves audit is included in the third-party audit report[3]. In the preparation of their reports, independent evaluators rely upon information furnished by Eni, without independent verification, with respect to property interests, production, current costs of operations and development, sales agreements, prices and other factual information and data that were accepted as represented by the independent evaluators. These data, equally used by Eni in its internal process, include logs, directional surveys, core and Pressure Volume Temperature (PVT) analysis, maps, oil/gas/water production/injection data of wells, reservoir studies, technical analysis relevant to field performance, development plans, future capital and operating costs.

In order to calculate the economic value of Eni s equity reserves, actual prices applicable to hydrocarbon sales, price adjustments required by applicable contractual arrangements and other pertinent information are provided by Eni to third-party evaluators. In 2013, Ryder Scott Company and DeGolyer and MacNaughton provided an independent evaluation of approximately 30% of Eni s total proved reserves at December 31, 2013[4], confirming, as in previous years, the reasonableness of Eni internal evaluation[5].

In the 2011-2013 three-year period, 92% of Eni total proved reserves were subject to an independent evaluation. As at December 31, 2013, the main Eni properties not subjected to independent evaluation in the last three years were M Boundi (Congo) and Elgin Franklin (United Kingdom).

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(1) See "Item 19 Exhibits" in the Annual Report on Form 20-F 2009.
(2) From 1991 to 2002, DeGolyer and MacNaughton; from 2003, also Ryder Scott.
(3) See "Item 19 Exhibits".
(4) Includes Eni s share of proved reserves of equity-accounted entities.
(5) See "Item 19 Exhibits".

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Summary of proved oil and gas reserves

The tables below provide a summary of proved oil and gas reserves of the Group companies and its equity-accounted entities by geographic area for the three years ended December 31, 2013, 2012 and 2011. Net proved reserves are set out in more detail under the heading "Supplemental oil and gas information" on page F-129.

HYDROCARBONS (mmBOE)	**Italy**	**Rest of Europe**	**North Africa**	**Sub-Saharan Africa**	**Kazakhstan**	**Rest of Asia**	**Americas**	**Australia and Oceania**	**Total reserves**
Consolidated subsidiaries									
Year ended Dec. 31, 2011	**707**	**630**	**2,031**	**1,021**	**950**	**230**	**238**	**133**	**5,940**
Developed	540	374	1,175	742	482	129	162	112	3,716
Undeveloped	167	256	856	279	468	101	76	21	2,224
Year ended Dec. 31, 2012	**524**	**591**	**1,915**	**1,048**	**1,041**	**184**	**236**	**128**	**5,667**
Developed	406	349	1,080	716	458	108	170	107	3,394
Undeveloped	118	242	835	332	583	76	66	21	2,273
Year ended Dec. 31, 2013	**499**	**557**	**1,783**	**1,155**	**1,035**	**263**	**240**	**176**	**5,708**
Developed	408	343	1,003	701	566	90	153	123	3,387
Undeveloped	91	214	780	454	469	173	87	53	2,321
Equity-accounted entities									
Year ended Dec. 31, 2011			**21**	**83**		**656**	**386**		**1,146**
Developed			19	4		5	26		54
Undeveloped			2	79		651	360		1,092
Year ended Dec. 31, 2012			**20**	**81**		**668**	**730**		**1,499**
Developed			20			82	20		122
Undeveloped				81		586	710		1,377
Year ended Dec. 31, 2013			**19**	**75**		**7**	**726**		**827**
Developed			19			3	18		40
Undeveloped				75		4	708		787
Consolidated subsidiaries and equity-accounted entities									
Year ended Dec. 31, 2011	**707**	**630**	**2,052**	**1,104**	**950**	**886**	**624**	**133**	**7,086**
Developed	540	374	1,194	746	482	134	188	112	3,770
Undeveloped	167	256	858	358	468	752	436	21	3,316
Year ended Dec. 31, 2012	**524**	**591**	**1,935**	**1,129**	**1,041**	**852**	**966**	**128**	**7,166**
Developed	406	349	1,100	716	458	190	190	107	3,516
Undeveloped	118	242	835	413	583	662	776	21	3,650
Year ended Dec. 31, 2013	**499**	**557**	**1,802**	**1,230**	**1,035**	**270**	**966**	**176**	**6,535**
Developed	408	343	1,022	701	566	93	171	123	3,427
Undeveloped	91	214	780	529	469	177	795	53	3,108

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LIQUIDS (mmBBL)	**Italy**	**Rest of Europe**	**North Africa**	**Sub-Saharan Africa**	**Kazakhstan**	**Rest of Asia**	**Americas**	**Australia and Oceania**	**Total reserves**
Consolidated subsidiaries									
Year ended Dec. 31, 2011	**259**	**372**	**917**	**670**	**653**	**106**	**132**	**25**	**3,134**
Developed	184	195	622	483	215	34	92	25	1,850
Undeveloped	75	177	295	187	438	72	40		1,284
Year ended Dec. 31, 2012	**227**	**351**	**904**	**672**	**670**	**82**	**154**	**24**	**3,084**
Developed	165	180	584	456	203	41	109	24	1,762
Undeveloped	62	171	320	216	467	41	45		1,322
Year ended Dec. 31, 2013	**220**	**330**	**830**	**723**	**679**	**128**	**147**	**22**	**3,079**
Developed	177	179	561	465	295	38	96	20	1,831
Undeveloped	43	151	269	258	384	90	51	2	1,248
Equity-accounted entities									
Year ended Dec. 31, 2011			**17**	**22**		**110**	**151**		**300**
Developed			16	4			25		45
Undeveloped			1	18		110	126		255
Year ended Dec. 31, 2012			**17**	**16**		**114**	**119**		**266**
Developed			17			8	19		44
Undeveloped				16		106	100		222
Year ended Dec. 31, 2013			**16**	**15**		**1**	**116**		**148**
Developed			16				19		35
Undeveloped				15		1	97		113
Consolidated subsidiaries and equity-accounted entities									
Year ended Dec. 31, 2011	**259**	**372**	**934**	**692**	**653**	**216**	**283**	**25**	**3,434**
Developed	184	195	638	487	215	34	117	25	1,895
Undeveloped	75	177	296	205	438	182	166		1,539
Year ended Dec. 31, 2012	**227**	**351**	**921**	**688**	**670**	**196**	**273**	**24**	**3,350**
Developed	165	180	601	456	203	49	128	24	1,806
Undeveloped	62	171	320	232	467	147	145		1,544
Year ended Dec. 31, 2013	**220**	**330**	**846**	**738**	**679**	**129**	**263**	**22**	**3,227**
Developed	177	179	577	465	295	38	115	20	1,866
Undeveloped	43	151	269	273	384	91	148	2	1,361

NATURAL GAS (BCF)	**Italy**	**Rest of Europe**	**North Africa**	**Sub-Saharan Africa**	**Kazakhstan**	**Rest of Asia**	**Americas**	**Australia and Oceania**	**Total reserves**
Consolidated subsidiaries									
Year ended Dec. 31, 2011	**2,491**	**1,425**	**6,190**	**1,949**	**1,648**	**685**	**590**	**604**	**15,582**
Developed	1,977	995	3,070	1,437	1,480	528	385	491	10,363
Undeveloped	514	430	3,120	512	168	157	205	113	5,219
Year ended Dec. 31, 2012	**1,633**	**1,317**	**5,558**	**2,061**	**2,038**	**562**	**449**	**572**	**14,190**
Developed	1,325	925	2,720	1,429	1,401	372	334	459	8,965
Undeveloped	308	392	2,838	632	637	190	115	113	5,225
Year ended Dec. 31, 2013	**1,532**	**1,247**	**5,231**	**2,374**	**1,957**	**744**	**509**	**848**	**14,442**
Developed	1,266	904	2,432	1,295	1,488	286	310	561	8,542
Undeveloped	266	343	2,799	1,079	469	458	199	287	5,900
Equity-accounted entities									
Year ended Dec. 31, 2011		**2**	**20**	**338**		**3,033**	**1,307**		**4,700**
Developed			17	4		24	8		53
Undeveloped		2	3	334		3,009	1,299		4,647
Year ended Dec. 31, 2012			**16**	**353**		**3,043**	**3,355**		**6,767**
Developed			16			402	6		424
Undeveloped				353		2,641	3,349		6,343
Year ended Dec. 31, 2013			**15**	**330**		**28**	**3,353**		**3,726**
Developed			15			14	5		34
Undeveloped				330		14	3,348		3,692
Consolidated subsidiaries and equity-accounted entities									
Year ended Dec. 31, 2011	**2,491**	**1,427**	**6,210**	**2,287**	**1,648**	**3,718**	**1,897**	**604**	**20,282**
Developed	1,977	995	3,087	1,441	1,480	552	393	491	10,416
Undeveloped	514	432	3,123	846	168	3,166	1,504	113	9,866
Year ended Dec. 31, 2012	**1,633**	**1,317**	**5,574**	**2,414**	**2,038**	**3,605**	**3,804**	**572**	**20,957**
Developed	1,325	925	2,736	1,429	1,401	774	340	459	9,389
Undeveloped	308	392	2,838	985	637	2,831	3,464	113	11,568
Year ended Dec. 31, 2013	**1,532**	**1,247**	**5,246**	**2,704**	**1,957**	**772**	**3,862**	**848**	**18,168**
Developed	1,266	904	2,447	1,295	1,488	300	315	561	8,576
Undeveloped	266	343	2,799	1,409	469	472	3,547	287	9,592

Volumes of oil and natural gas applicable to long-term supply agreements with foreign governments in mineral assets where Eni is operator totaled 536 mmBOE as of December 31, 2013 (648 and 647 mmBOE as of December 31, 2012 and 2011, respectively). Said volumes are not included in reserves volumes shown in the table herein.

	Subsidiaries			**Equity-accounted entities**		
	2011	**2012**	**2013**	**2011**	**2012**	**2013**
			(mmBOE)			
Additions to proved reserves	183	549	621	644	404	
Purchases of minerals-in-place	2		4			
Sales of minerals-in-place	(9)	(212)	(13)		(38)	(652)

Production for the year	(568)	(610)	(571)	(9)	(13)	(20)

	Subsidiaries and equity-accounted entities		
	2011	2012	2013
		(%)	
Proved reserves replacement ratio of subsidiaries and equity-accounted entities, all sources	142	113	(7)

Eni s proved reserves as of December 31, 2013 totaled 6,535 mmBOE (liquids 3,227 mmBBL; natural gas 18,168 BCF). Eni s proved reserves reported a decrease of 631 mmBOE, or 8.8%, from December 31, 2012. All sources additions to proved reserves were negative in 2013 due to the divestment of our equity stake in the joint venture Severenergia which owns and operates gas fields in Siberia, Russia. This disposal reduced our proved reserves by 652 mmBOE (for further information see "Eni s share of equity-accounted entities"). Excluding sales of mineral-in-place,

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additions to proved reserves booked in 2013 were 621 mmBOE, all relating to Eni s subsidiaries. Other proved property divestments were made in the United Kingdom (13 mmBOE). Acquisitions referred to interests in assets located in Egypt (4 mmBOE).

Price effects were negligible, leading to an upward revision of 14 mmBOE, due to a lowered Brent price used in the reserve estimation process down to $108 per barrel in 2013 compared to $111 per barrel in 2012.

The methods (or technologies) used in the Eni s proved reserves assessment in 2013 depend on stage of development, quality and completeness of data, and production history availability. The methods include volumetric estimates, analogies, reservoir modeling, decline curve analysis or a combination of such methods. The data considered for these analyses are obtained from a combination of reliable technologies that produce consistent and repeatable results including well or field measurements (i.e. logs, core samples, pressure information, fluid samples, production test data and performance data) and indirect measurements (i.e. seismic data). However for each reservoir assessment the most suitable combination of technologies and methods is applied providing a high degree of confidence in establishing reliable reserves estimates.

The all sources reserves replacement ratio achieved by Eni s subsidiaries and equity-accounted entities was negative in 2013 (113% in 2012 and 142% in 2011) and it was influenced by the assets disposal in Russia. Excluding the portfolio activities the organic reserves replacement ratio was 105% (153% in 2012 and 143% in 2011). The all sources reserves replacement ratio was calculated by dividing additions to proved reserves including sales and purchases of mineral-in-place by total production, each as derived from the tables of changes in proved reserves prepared in accordance with FASB Extractive Activities - Oil & Gas (Topic 932) (see the supplemental oil and gas information in "Item 18 Consolidated Financial Statements"). The reserves replacement ratio is a measure used by management to assess the extent to which produced reserves in the year are replaced by booked reserves total additions. Management considers the reserve replacement ratio to be an important indicator of the Company s ability to sustain its growth perspectives. However, this ratio measures past performances and is not an indicator of future production because the ultimate recovery of reserves is subject to a number of risks and uncertainties. These include the risks associated with the successful completion of large-scale projects, including addressing ongoing regulatory issues and completion of infrastructures, as well as changes in oil and gas prices, political risks and geological and environmental risks. Specifically, in recent years Eni s reserves replacement ratio has been affected by the impact of changes in hydrocarbon prices on reserves entitlements in the Company s production sharing agreements and similar contractual schemes. In accordance with such contracts, Eni is entitled to a portion of field reserves, the sale of which should cover expenditures incurred by the Company to develop and operate the field. The higher the hydrocarbons reference prices used to determine year-end amounts of Eni s proved reserves, the lower the number of barrels necessary to cover the same amount of expenditures. See "Item 3 Risks associated with exploration and production of oil and natural gas *(vii) Uncertainties in estimates of oil and natural gas reserves*".

The average reserves life index of Eni s proved reserves was 11.1 years as of December 31, 2013 which included reserves of both subsidiaries and equity-accounted entities.

Eni s subsidiaries

Eni s subsidiaries added 621 mmBOE of proved oil and gas reserves in 2013. This comprised 299 mmBBL of liquids and 1,773 BCF of natural gas. Additions to proved reserves derived from: (i) revisions of previous estimates were 508 mmBOE mainly reported in Congo, Iraq, Australia and Nigeria; (ii) extensions, discoveries and others were 108 mmBOE, with major increases booked in Angola, Indonesia and the United States; and (iii) improved recovery were 5 mmBOE mainly reported in Nigeria.

Eni s share of equity-accounted entities

Eni s share of equity-accounted entities reported the divestment of Eni s 60% interest in Artic Russia to certain Gazprom companies. Artic Russia is the parent company with a 49% stake of Severenergia, which holds four licenses for the exploration and production of hydrocarbons in the Region of Yamal Nenets (Siberia). On January 15, 2014, the consideration for the disposal equal to euro 2.16 billion ($2,940 million) was cashed in.

Proved undeveloped reserves

Proved undeveloped reserves as of December 31, 2013 totaled 3,108 mmBOE. At year end, proved undeveloped reserves of liquids amounted to 1,361 mmBBL, mainly concentrated in Africa and Kazakhstan. Proved undeveloped reserves of natural gas amounted to 9,592 BCF, mainly located in Africa and Venezuela. Proved undeveloped reserves of consolidated subsidiaries amounted to 1,248 mmBBL of liquids and 5,900 BCF of natural gas.

In 2013, total proved undeveloped reserves decreased by 542 mmBOE mainly due to disposal in Russia as well as due to upwards and downwards revisions mainly related to contractual and technical revisions.

During 2013, Eni converted 337 mmBOE of proved undeveloped reserves to proved developed reserves due to development activities, production start-ups and revisions. The main reclassifications to proved developed reserves related to the following fields/projects: Kashagan (Kazakhstan), CAFC-MLE and Block 208 (Algeria), Jasmine (United Kingdom) and Zubair (Iraq).

In 2013, capital expenditures amounted to approximately euro 2 billion and was made to progress the development of proved undeveloped reserves.

Reserves that remain proved undeveloped for five or more years are a result of several factors that affect the timing of the projects development and execution, such as the complex nature of the development project in adverse and remote locations, physical limitations of infrastructures or plant capacity and contractual limitations that establish production levels. The Company estimates that approximately 0.8 BBOE of proved undeveloped reserves have remained undeveloped for five years or more with respect to the balance sheet date, mainly related to: (i) the Kashagan project in Kazakhstan for approximately 0.4 BBOE which will be progressively reclassified to proved developed as a result of hooking-up new producing wells which are currently being drilled and plant capacity expansion as part of the completion of the sanctioned Phase 1 of the global development plan of the Kashagan field (the so-called Experimental Program); (ii) some Libyan gas fields (0.3 BBOE) where development completion and production start-up are planned according to the delivery obligations set forth in a long-term gas supply agreement currently in force. In order to secure fulfillment of the contractual delivery quantities, Eni will implement phased production start-up from the relevant fields, which are expected to be put in production over the next several years; and (iii) other minor projects where development activities are progressing. (See also our discussion under the "Risk factors" section about risks associated with oil and gas development projects on page 9).

Eni remains strongly committed to put these projects into production over the next few years. The length of the development period is a function of a range of external factors, such as for example the type of development, the location and physical operating environment of the field or the absence of infrastructure, considering that the majority of our projects are infrastructure-driven, and not a function of internal factors, such as an insufficient devotion of resources by Eni or a diminished commitment on the part of Eni to complete the project.

Delivery commitments

Eni sells crude oil and natural gas from its producing operations under a variety of contractual obligations. Some of these contracts, mostly relating to natural gas, specify the delivery of fixed and determinable quantities.

Eni is contractually committed under existing contracts or agreements to deliver in the next three years mainly natural gas to third parties for a total of approximately 348 mmBOE from producing assets located mainly in Algeria, Australia, Egypt, Libya, Nigeria and Norway.

The sales contracts contain a mix of fixed and variable pricing formulas that are generally referenced to the market price for crude oil, natural gas or other petroleum products.

Management believes it can satisfy these contracts from quantities available from production of the Company s proved developed reserves and supplies from third parties based on existing contracts. Production will account for approximately 75% of delivery commitments.

Eni has met all contractual delivery commitments as of December 31, 2013.

Oil and gas production, production prices and production costs

The matters regarding future production, additions to reserves and related production costs and estimated reserves discussed below and elsewhere herein are forward-looking statements that involve risks and uncertainties that could cause the actual results to differ materially from those in such forward-looking statements. Such risks and uncertainties relating to future production and additions to reserves include political developments affecting the award of exploration or production interests or world supply and prices for oil and natural gas, or changes in the underlying economics of certain of Eni s important hydrocarbons projects. Such risks and uncertainties relating to future production costs include delays or unexpected costs incurred in Eni s production operations.

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In 2013, oil and natural gas production available for sale averaged 1,537 KBOE/d (1,631 KBOE/d in 2012) declined by 5.8% from 2012, reflecting significant force majeure events in particular in Libya, Nigeria and Algeria, which considerably impacted the production level and the disposals made in the first half of 2012, while it was partially helped by the performance of the Elgin-Franklin field (Eni s interest 21.87%) in the United Kingdom, operated by another oil major, which was off line in 2012 due to a gas leak. The contribution of the new fields start-ups and continuing production ramp-ups mainly in Algeria and Egypt partly offset the effects of planned facility downtimes and technical problems, in the North Sea and in the Gulf of Mexico respectively, as well as mature field declines.

Liquids production (833 KBBL/d) decreased by 49 KBBL/d, or 5.6% from the previous year, driven mainly by lower production in Libya and Nigeria, planned and extraordinary downtimes and mature field declines. These negatives were partly offset by new field start-ups and production ramp-ups mainly in: (i) Algeria, following the start-up of the MLE-CAFC (Eni s interest 75%) and the El Merk (Eni s interest 12.25%) projects; (ii) Egypt, following the ramp-up of Meleiha Area (Eni s interest 76%); and (iii) Iraq, due to increased production at the Zubair field (Eni s interest 41.6%).

Natural gas production (3,868 mmCF/d) decreased by 250 mmCF/d, or 6.1%. The lower production in Nigeria, planned and extraordinary downtimes and mature field declines were partially offset by the contribution of new field start-ups and ramp-ups of the year, mainly in Algeria and the United Kingdom following the start-up of Jasmine field (Eni s interest 33%).

Oil and gas production sold amounted to 555.3 mmBOE. The 35.7 mmBOE difference over production (591 mmBOE) reflected mainly volumes of natural gas consumed in operations (30 mmBOE). Approximately 60% of liquids production sold (299.5 mmBBL) was destined to Eni s Refining & Marketing Division (of which 25% was processed in Eni s refineries). About 27% of natural gas production sold (1,405 BCF) was destined to Eni s Gas & Power Division.

The tables below provide Eni subsidiaries and its equity-accounted entities production, by final product sold of liquids and natural gas by geographical area of each of the last three fiscal years.

LIQUIDS PRODUCTION

	2011		2012		2013	
(KBBL/d)	Eni consolidated subsidiaries	Eni share of equity-accounted entities	Eni consolidated subsidiaries	Eni share of equity-accounted entities	Eni consolidated subsidiaries	Eni share of equity-accounted entities
Italy	64		63		71	
Rest of Europe	120		95		77	
North Africa	204	5	267	4	248	4
Sub-Saharan Africa	275	3	245	2	242	
Kazakhstan	64		61		61	
Rest of Asia	33	1	41	3	43	6
Americas	55	10	72	11	61	10
Australia and Oceania	11		18		10	
	826	**19**	**862**	**20**	**813**	**20**

NATURAL GAS PRODUCTION AVAILABLE FOR SALE [(a)]

	2011		2012		2013	

(mmCF/d)	Eni consolidated subsidiaries	Eni share of equity-accounted entities	Eni consolidated subsidiaries	Eni share of equity-accounted entities	Eni consolidated subsidiaries	Eni share of equity-accounted entities
Italy	648		667		593	
Rest of Europe	498		421		395	
North Africa	1,165	4	1,589	3	1,510	4
Sub-Saharan Africa	422		444		349	7
Kazakhstan	212		202		195	
Rest of Asia	378	20	355	68	322	154
Americas	323		273		234	
Australia and Oceania	93		96		105	
	3,739	**24**	**4,047**	**71**	**3,703**	**165**

(a) It excludes production volumes of natural gas consumed in operations. Said volumes were 451, 383 and 321 mmCF/d in 2013, 2012 and 2011, respectively.

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Volumes of oil and natural gas purchased under long-term supply contracts with foreign governments or similar entities in properties where Eni acts as producer totaled 67 KBOE/d, 78 KBOE/d and 28 KBOE/d in 2013, 2012 and 2011, respectively.

The tables below provide Eni subsidiaries and its equity-accounted entities average sales prices per unit of liquids and natural gas by geographical area for each of the last three fiscal years. Also Eni subsidiaries and its equity-accounted entities average production cost per unit of production are provided. The average production cost does not include any ad valorem or severance taxes.

AVERAGE SALES PRICES AND PRODUCTION COST PER UNIT OF PRODUCTION

($)	Italy	Rest of Europe	North Africa	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2011									
Consolidated subsidiaries									
Oil and condensates, per BBL	101.20	97.56	97.63	110.09	98.68	101.09	101.15	98.05	**102.47**
Natural gas, per KCF	11.56	9.72	5.95	1.97	0.57	5.27	4.02	7.38	**6.44**
Average production cost, per BOE	11.17	10.31	5.96	18.32	6.37	8.28	12.38	12.14	**10.86**
Equity-accounted entities									
Oil and condensates, per BBL		97.18	17.98	108.92		74.98	93.03		**84.78**
Natural gas, per KCF		10.65	5.39			15.68			**13.89**
Average production cost, per BOE		26.91	10.82	11.43		7.68	46.77		**26.76**
2012									
Consolidated subsidiaries									
Oil and condensates, per BBL	100.52	100.67	103.63	108.34	102.25	103.44	85.94	102.06	**103.06**
Natural gas, per KCF	10.68	10.13	8.13	2.16	0.67	5.94	2.90	7.73	**7.14**
Average production cost, per BOE	11.60	13.43	6.28	18.65	6.73	8.37	10.46	13.23	**10.82**
Equity-accounted entities									
Oil and condensates, per BBL		93.11	17.93	112.28		40.36	93.45		**77.94**
Natural gas, per KCF		11.64	4.91			6.17			**6.16**
Average production cost, per BOE		30.10	10.35	10.60		4.37	46.01		**20.21**
2013									
Consolidated subsidiaries									
Oil and condensates, per BBL	98.50	98.97	100.42	105.13	99.37	99.69	85.27	98.72	**100.20**
Natural gas, per KCF	11.65	10.62	7.96	2.16	0.64	5.83	3.37	7.80	**7.41**
Average production cost, per BOE	14.58	17.49	6.72	19.60	7.23	9.32	12.08	18.17	**12.19**
Equity-accounted entities									
Oil and condensates, per BBL			17.96			33.87	93.32		**64.92**
Natural gas, per KCF			6.29			3.49			**4.00**
Average production cost, per BOE			11.87			3.48	50.57		**16.68**

Development activities

In 2013, a total of 463 development wells were drilled (187.2 of which represented Eni s share) as compared to 351 development wells drilled in 2012 (163.6 of which represented Eni s share) and 407 development wells drilled in 2011 (186.1 of which represented Eni s share). The drilling of 130 wells (45 of which represented Eni s share) is currently underway.

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The table below summarizes the number of the Company s net interest in productive and dry development wells completed in each of the past three years and the status of the Company s development wells in the process of being drilled as of December 31, 2013. A dry well is one found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

DEVELOPMENT WELL ACTIVITY

	Net wells completed						Wells in progress at Dec. 31,	
	2011		2012		2013		2013	
(units)	Productive	Dry	Productive	Dry	Productive	Dry	Gross	Net
Italy	25.3		18.0	1.0	7.4	1.0	3.0	3.0
Rest of Europe	3.3	0.3	2.9	0.6	6.3		31.0	5.9
North Africa	55.9	1.1	46.0	1.6	61.6	3.3	20.0	11.3
Sub-Saharan Africa	28.2	1.0	27.4	0.3	26.3	1.2	20.0	5.1
Kazakhstan	1.3		1.4		0.3		17.0	3.1
Rest of Asia	39.2	2.5	41.2	0.1	61.7	4.3	26.0	11.4
Americas	27.6		23.1		13.8		12.0	4.8
Australia and Oceania	0.4						1.0	0.4
Total including equity-accounted entities	**181.2**	**4.9**	**160.0**	**3.6**	**177.4**	**9.8**	**130.0**	**45.0**

Exploration activities

In 2013, a total of 53 new exploratory wells were drilled (27.8 of which represented Eni s share), as compared to 60 exploratory wells drilled in 2012 (34.1 of which represented Eni s share) and 56 exploratory wells drilled in 2011 (28 of which represented Eni s share).

The overall commercial success rate was 36.9% (38.5% net to Eni) as compared to 40% (40.8% net to Eni) and 42% (38.6% net to Eni) in 2012 and 2011, respectively.

The following table summarizes the Company s net interests in productive and dry exploratory wells completed in each of the last three fiscal years and the number of exploratory wells in the process of being drilled and evaluated as of December 31, 2013. A dry well is one found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

EXPLORATORY WELL ACTIVITY

	Net wells completed						Wells in progress at Dec. 31, (1)	
	2011		2012		2013		2013	
(units)	Productive	Dry	Productive	Dry	Productive	Dry	Gross	Net
Italy			1.0				5.0	3.4

Rest of Europe	0.3	0.7	1.0	1.0		3.4	17.0	6.2
North Africa	6.2	3.4	6.3	11.3	4.9	5.4	14.0	9.8
Sub-Saharan Africa	0.6	2.6	4.5	5.1	3.2	6.6	60.0	24.3
Kazakhstan				0.8		0.4	6.0	1.1
Rest of Asia	0.2	7.6	0.5	0.6	4.3	2.7	21.0	8.2
Americas	2.5			0.1	0.2	1.2	4.0	1.2
Australia and Oceania		1.4		0.4		0.5	2.0	0.8
Total including equity-accounted entities	**9.8**	**15.7**	**13.3**	**19.3**	**12.6**	**20.2**	**129.0**	**55.0**

(1) Includes temporary suspended wells pending further evaluation.

Oil and gas properties, operations and acreage

As of December 31, 2013, Eni s mineral right portfolio consisted of 976 exclusive or shared rights for exploration and development in 42 countries on five continents for a total acreage of 276,256 square kilometers net to Eni of which developed acreage of 41,538 square kilometers and undeveloped acreage of 234,718 square kilometers.

In 2013, changes in total net acreage mainly derived from: (i) new leases mainly in Cyprus, Kenya, Greenland, Norway, Russia and Vietnam for a total acreage of approximately 48,000 square kilometers; (ii) the total relinquishment of licenses mainly in Angola, China, Congo, Egypt, Poland, Russia, Timor Leste, the United States and the United

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Kingdom, covering an acreage of approximately 15,000 square kilometers; and (iii) partial relinquishment or interest reduction in Congo, Indonesia, Mozambique and Timor Leste for approximately 6,000 square kilometers.

The table below provides certain information about the Company s oil and gas properties. It provides the total gross and net developed and undeveloped oil and natural gas acreage in which the Group and its equity-accounted entities had interest as of December 31, 2013. A gross acreage is one in which Eni owns a working interest.

	December 31, 2012	December 31, 2013						
	Total net acreage (a)	Number of interests	Gross developed acreage (a) (b)	Gross undeveloped acreage (a)	Total gross acreage (a)	Net developed acreage (a) (b)	Net undeveloped acreage (a)	Total net acreage (a)
EUROPE	**27,423**	**264**	**16,170**	**40,753**	**56,923**	**10,907**	**26,111**	**37,018**
Italy	**17,556**	**151**	**10,663**	**10,815**	**21,478**	**8,948**	**8,334**	**17,282**
Rest of Europe	**9,867**	**113**	**5,507**	**29,938**	**35,445**	**1,959**	**17,777**	**19,736**
Cyprus		3		12,523	12,523		10,018	10,018
Croatia	987	2	1,975		1,975	987		987
Norway	2,676	57	2,264	9,302	11,566	346	3,433	3,779
Poland	1,968	2		969	969		969	969
Ukraine	1,941	12	50	3,840	3,890	30	1,911	1,941
United Kingdom	914	34	1,218	223	1,441	596	42	638
Other countries	1,381	3		3,081	3,081		1,404	1,404
AFRICA	**142,796**	**280**	**66,341**	**185,574**	**251,915**	**20,131**	**116,965**	**137,096**
North Africa	**21,390**	**116**	**32,560**	**14,334**	**46,894**	**14,150**	**6,262**	**20,412**
Algeria	1,232	42	3,223	187	3,410	1,148	31	1,179
Egypt	4,590	53	4,926	5,460	10,386	1,778	1,887	3,665
Libya	13,294	10	17,947	8,687	26,634	8,950	4,344	13,294
Tunisia	2,274	11	6,464		6,464	2,274		2,274
Sub-Saharan Africa	**121,406**	**164**	**33,781**	**171,240**	**205,021**	**5,981**	**110,703**	**116,684**
Angola	6,079	71	6,498	14,991	21,489	802	3,641	4,443
Congo	5,035	28	1,835	2,890	4,725	1,017	2,108	3,125
Democratic Republic of Congo	263	1		478	478		263	263
Gabon	7,615	6		7,615	7,615		7,615	7,615
Ghana	1,885	2		4,676	4,676		1,664	1,664
Kenya	35,724	4		46,410	46,410		38,930	38,930
Liberia	2,036	3		7,365	7,365		1,841	1,841
Mozambique	9,069	1		10,207	10,207		5,103	5,103
Nigeria	7,646	41	25,448	10,838	36,286	4,162	3,484	7,646
Togo	6,192	2		6,192	6,192		6,192	6,192
Other countries	39,862	5		59,578	59,578		39,862	39,862
ASIA	**58,042**	**70**	**19,013**	**168,024**	**187,037**	**6,650**	**72,664**	**79,314**
Kazakhstan	**869**	**6**	**2,391**	**2,542**	**4,933**	**442**	**427**	**869**
Rest of Asia	**57,173**	**64**	**16,622**	**165,482**	**182,104**	**6,208**	**72,237**	**78,445**
China	10,495	8	76	5,130	5,206	19	5,130	5,149
India	6,208	11	206	16,546	16,752	109	6,058	6,167
Indonesia	19,734	13	3,220	25,779	28,999	1,218	17,991	19,209
Iran	820	4	1,456		1,456	820		820
Iraq	352	1	1,074		1,074	446		446

Pakistan	10,533	18	10,390	17,731	28,121	3,396	6,939	10,335
Russia	1,469	3		62,592	62,592		20,862	20,862
Timor Leste	4,118	1		1,538	1,538		1,230	1,230
Turkmenistan	200	1	200		200	200		200
Vietnam		3		21,566	21,566		10,783	10,783
Other countries	3,244	1		14,600	14,600		3,244	3,244
AMERICAS	**9,075**	**348**	**4,809**	**15,268**	**20,077**	**3,141**	**6,065**	**9,206**
Ecuador	1,985	1	1,985		1,985	1,985		1,985
Greenland		1		2,630	2,630		920	920
Trinidad & Tobago	66	1	382		382	66		66
United States	4,632	331	1,640	5,089	6,729	822	3,021	3,843
Venezuela	1,066	6	802	2,002	2,804	268	798	1,066
Other countries	1,326	8		5,547	5,547		1,326	1,326
AUSTRALIA AND OCEANIA	**13,834**	**14**	**1,140**	**22,436**	**23,576**	**709**	**12,913**	**13,622**
Australia	13,796	14	1,140	22,436	23,576	709	12,913	13,622
Other countries	38							
Total	**251,170**	**976**	**107,473**	**432,055**	**539,528**	**41,538**	**234,718**	**276,256**

(a) Square kilometers.

(b) Developed acreage refers to those leases in which at least a portion of the area is in production or encompasses proved developed reserves.

The table below provides the number of gross and net productive oil and natural gas wells in which the Group companies and its equity-accounted entities had an interest as of December 31, 2013. A gross well is a well in which Eni owns a working interest. The number of gross wells is the total number of wells in which Eni owns a whole or fractional working interest. The number of net wells is the sum of the whole or fractional working interests in a gross well. One or more completions in the same bore hole are counted as one well. Productive wells are producing wells and wells capable of production. The total number of oil and natural gas productive wells is 8,697 (3,424.4 of which represent Eni s share).

Productive oil and gas wells at Dec. 31, 2013 [(a)]

	Oil wells		Natural gas wells	
(units)	Gross	Net	Gross	Net
Italy	240.0	194.1	615.0	531.5
Rest of Europe	415.0	60.8	182.0	90.2
North Africa	1,590.0	820.4	199.0	85.8
Sub-Saharan Africa	2,908.0	585.9	339.0	25.5
Kazakhstan	104.0	29.7		
Rest of Asia	644.0	417.3	897.0	341.6
Americas	191.0	105.4	352.0	129.1
Australia and Oceania	7.0	3.8	14.0	3.3
Total including equity-accounted entities	**6,099.0**	**2,217.4**	**2,598.0**	**1,207.0**

(a) Multiple completion wells included above: approximately 2,162 (761.2 net to Eni).

Eni s principal oil and gas properties are described below. In the discussion that follows, references to hydrocarbon production are intended to represent hydrocarbon production available for sale.

Italy

Eni has been operating in Italy since 1926. In 2013, Eni s oil and gas production amounted to 179 KBOE/d. Eni s activities in Italy are deployed in the Adriatic and Ionian Sea, the Central Southern Apennines, mainland and offshore Sicily and the Po Valley. Eni s exploration and development activities in Italy are regulated by concession contracts (67 operated onshore and 72 operated offshore).

The Adriatic and Ionian Sea represents Eni s main production area, accounting for 49% of Eni s domestic production in 2013. Main operated fields are Barbara, Annamaria, Angela-Angelina, Porto Garibaldi, Cervia, Bonaccia, Luna and Hera Lacinia.

Eni is the operator of the Val d Agri concession (Eni s interest 60.77%) in the Basilicata Region in Southern Italy. Production from the Monte Alpi, Monte Enoc and Cerro Falcone fields is fed by 29 production wells and is treated by the Viggiano oil center. In 2013, the Val d Agri concession produced 34% of Eni s production in Italy.

Eni operates 12 production concessions onshore and 2 offshore Sicily. The main fields are Gela, Ragusa, Tresauro, Giaurone, Fiumetto and Prezioso, which in 2013 accounted for approximately 10% of Eni s production in Italy.

The development activity for the year was focused on maintenance and optimization of producing fields and existing facilities.

In the Val d Agri concession the development plan is ongoing as agreed with the Basilicata Region in 1998: (i) the construction of a new gas treatment unit progressed, aiming at improving the environmental performance of the treatment unit and achieving a production capacity of 104 KBBL/d; and (ii) start-up of Alli 2 producing well.

Other main development activities concerned the maintenance and production optimization at the fields located in the Adriatic offshore and onshore area in Sicily as well as the upgrading of compression and hydrocarbon treatment facilities at the production platform of the Barbara field.

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In the medium term, management expects a stable production driven by continuing ramp-up at the Val d Agri fields, new field projects and production optimization activities offsetting mature field declines.

Rest of Europe

Eni s operations in the Rest of Europe are conducted mainly in Croatia, Norway and the United Kingdom. In 2013, the Rest of Europe accounted for 10% of Eni s total worldwide production of oil and natural gas.

Croatia. Eni has been present in Croatia since 1996. In 2013, Eni s production of natural gas averaged 41 mmCF/d. Activities are deployed in the Adriatic Sea near the city of Pula.

Exploration and production activities in Croatia are regulated by PSAs.

The main producing gas fields are Annamaria, Ivana, Ika & Ida, Ana, Vesna, Irina, Marica and Katarina and are operated by Eni through a 50/50 joint operating company with the Croatian oil company INA.

Cyprus. In January 2013, Exploration and Production Sharing Contracts (EPSC) were signed with the Republic of Cyprus, for Blocks 2, 3 and 9 located in the Cypriot deep offshore portion of the Levantine Basin. The new acreage encompasses an area of around 12,530 square kilometers, and marks the entry of Eni in the Country. Eni was awarded the three blocks whilst leading the consortium with an 80% interest.

Norway. Eni has been operating in Norway since 1965. Eni s activities are performed in the Norwegian Sea, in the Norwegian section of the North Sea and in the Barents Sea. Eni s production in Norway amounted to 103 KBOE/d in 2013.

Exploration and production activities in Norway are regulated by Production Licenses (PL). According to a PL, the holder is entitled to perform seismic surveys and drilling and production activities for a given number of years with possible extensions.

Eni currently holds interests in 10 production areas in the Norwegian Sea. The principal producing fields are Åsgard (Eni s interest 14.82%), Kristin (Eni s interest 8.25%), Heidrun (Eni s interest 5.17%), Mikkel (Eni s interest 14.9%), Tyrihans (Eni s interest 6.2%), Marulk (Eni operator with a 20% interest) and Morvin (Eni s interest 30%) which in 2013 accounted for 79% of Eni s production in Norway. The Skuld field (Eni s interest 11.5%) started up with a production of approximately 30 KBOE/d (approximately 4 KBOE/d net to Eni).

Eni holds interests in 5 production licenses in the Norwegian section of the North Sea. The main producing field is Ekofisk (Eni s interest 12.39%) in PL 018, which in 2013 produced approximately 22 KBOE/d net to Eni and accounted for 21% of Eni s production in Norway. The license expires in 2028, and negotiations are ongoing to grant an extension. Activities were performed during the year to maintain and optimize the production rate by means of drilling of infilling wells, upgrading of existing facilities and optimization of water injection. The development of the South Area was completed in the year.

Eni is currently performing exploration and development activities in the Barents Sea. Operations have been focused on developing the Goliat discovery made in 2000 at a water depth of 370 meters in PL 229 (Eni operator with a 65% interest). The license expires in 2042. The project is progressing; the production start-up is expected by the end of 2014 with a production of 56 KBBL/d net to Eni in 2015.

During the year, Eni was awarded the operatorship and a 40% interest in the PL 717, PL 712, PL 716 and PL 697 (Eni s interest 65%) exploration licenses, as well as a 30% stake in the PL 696 and 714 licenses in the Barents Sea.

Exploration activities yielded positive results in the: (i) PL 532 license (Eni s interest 30%) with the oil and gas Skavl discovery, in addition to the recent oil and gas discoveries of Skrugard and Havis. The total recoverable resources are estimated at over 500 million barrels at 100% and are planned to be put in production by means of fast-track synergic development; and (ii) PL 479 license (Eni s interest 19.6%) with the Smørbukk near field gas discovery that will leverage on the synergies with the existing production facilities.

United Kingdom. Eni has been present in the United Kingdom since 1964. Eni s activities are carried out in the British section of the North Sea, the Irish Sea and Atlantic Ocean. In 2013, Eni s net production of oil and gas averaged 39 KBOE/d.

Exploration and production activities in the United Kingdom are regulated by concession contracts.

Within its strategy of portfolio optimization, Eni finalized the disposal of 19 development/production fields and 11 exploration licenses.

Eni currently holds interests in 5 production areas of which the Hewett Area is operated by Eni with an 89.3% interest. The other fields are Elgin/Franklin (Eni s interest 21.87%), West Franklin (Eni s interest 21.87%), Liverpool Bay (Eni s interest 53.9%; 100% after acquisition of the remaining share in 2014), J Block Area (Eni s interest 33%) and MacCulloch (Eni s interest 40%), which in 2013 accounted for 80% of Eni s production in the United Kingdom.

Production started at the oil and gas Jasmine field (Eni s interest 33%), with the installation activities and linkage to productive and treatment facilities. A peak of approximately 117 KBBL/d (39 KBBL/d net to Eni) is expected in 2014.

Other development activities concerned the West Franklin field with the construction and installation of production platform and linkage to nearby treatment facilities. Start-up is expected at the end of 2014.

North Africa

Eni s operations in North Africa are conducted in Algeria, Egypt, Libya and Tunisia. In 2013, North Africa accounted for 34% of Eni s total worldwide production of oil and natural gas.

Algeria. Eni has been present in Algeria since 1981. In 2013, Eni s oil and gas production averaged 81 KBOE/d.

Operated and participated activities are located in the Bir Rebaa area in the South-Eastern Desert: (i) Blocks 403a/d (Eni s interest 100%); (ii) Block Rom North (Eni s interest 35%); (iii) Blocks 401a/402a (Eni s interest 55%); (iv) Blocks 403 (Eni s interest 50%) and 404 (Eni s interest 12.25%, non-operated); (v) Blocks 208 (Eni s interest 12.25%, non-operated) and 405b (Eni s interest 75%); and

(vi) Block 212 (Eni s interest 22.38%) with discoveries already made.

Exploration and production activities in Algeria are regulated by production sharing agreements and concession contracts.

Production in Block 403a/d and Rom North comes mainly from the HBN and Rom and satellite fields and represented approximately 18% of Eni s production in Algeria in 2013.

Production in Blocks 401a/402a comes mainly from the ROD/SFNE and satellite fields and accounted for approximately 20% of Eni s production in Algeria in 2013.

The main fields in Block 403 are BRN, BRW and BRSW which accounted for approximately 14% of Eni s production in Algeria in 2013.

The main fields in Block 404 are HBN and HBNS and satellites which accounted for approximately 30% of Eni s production in Algeria in 2013.

In 2013, production started at the MLE-CAFC project in Block 405b. The natural gas treatment plant has a production and export capacity of 320 mmCF/d of gas, 15 KBBL/d of oil and condensates and 12 KBBL/d of LPG. Four export pipelines link it to the national grid system. In the year MLE-CAFC fields accounted for approximately 14% of Eni s production in Algeria. The integrated project MLE-CAFC targets a production plateau of approximately 33 KBOE/d net to Eni by 2017.

In Block 208, the El Merk field started up with the construction of a gas treatment plant for approximately 600 mmCF/d, two oil trains for 65 KBBL/d each and three export pipelines linked to the local network. The El Merk field accounted approximately 4% of Eni s production in Algeria in 2013. Production peak of 18 KBOE/d net to Eni is expected in 2015.

Egypt. Eni has been present in Egypt since 1954. In 2013, Eni s share of production in this Country amounted to 215 KBOE/d and accounted for 14% of Eni s total annual hydrocarbon production. Eni s main producing liquid fields are located in the Gulf of Suez, primarily the Belayim field (Eni s interest 100%), and in the Western Desert mainly the Meleiha (Eni s interest 76%) and the Ras Qattara (Eni s interest 75%) concessions. Gas production mainly comes from the operated or participated concession of North Port Said (Eni s interest 100%), El Temsah (Eni s interest 50%), Baltim (Eni s interest 50%) and Ras el Barr (Eni s interest 50%, non operated), located offshore the Nile Delta. In 2013, production from these large concessions accounted for approximately 94% of Eni s production in Egypt.

Exploration and production activities in Egypt are regulated by production sharing agreements.

Development activities concerned: (i) infilling activities at the Belayim, Denise (Eni s interest 50%), Tuna (Eni s interest 50%) fields and the Western Desert Area to optimize the mineral potential recovery factor; (ii) completion of

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the drilling activities at the Seth field (Eni s interest 50%); and (iii) development program of the DEKA field (Eni s interest 50%) and the Emry Deep discovery (Eni s interest 76%).

In 2013, Eni was awarded the operatorship and a 100% interest in an exploration block in deep waters in the Eastern Mediterranean Sea.

Exploration activities yielded positive results in the: (i) Meleiha development lease with three near field oil and gas discoveries and the Rosa North-1X oil discovery, where the drilling activities are underway. Development activities plan to leverage on the existing production facilities; and (ii) two near field oil discoveries in the Belayim concession.

Libya. Eni started operations in Libya in 1959.

Throughout the course of 2013, Eni s production performance in Libya was negatively impacted due to force majeure events reflecting ongoing instability in the socio-political context of the Country. It is worth mentioning that Eni is currently engaged in the recovery of the full production plateau at its producing assets in the Country, following the internal conflict of 2011 that forced the Company to shut down almost all its producing facilities including gas exports for a period of about 8 months with a material impact on production volumes and operating results of that year. Due to the complexity of the transition period which the Country is currently undergoing, Eni is still in the process of restoring the full production plateau at its Libyan fields. For the full year 2013 Eni s facilities in Libya produced a level of 219 KBOE/d, which is lower than the pre-crisis production plateau of approximately 270 KBOE/d attained in 2010. For further information on this matter, see "Item 3 Risk factors".
Production activity is carried out in the Mediterranean Sea near Tripoli and in the Libyan Desert Area and includes six contract areas. Onshore contract areas are: (i) Area A consisting in the former concession 82 (Eni s interest 50%); (ii) Area B, former concessions 100 (Bu Attifel field) and the NC 125 Block (Eni s interest 50%); (iii) Area E with El Feel (Elephant) field (Eni s interest 33.3%); and (iv) Area F with Block 118 (Eni s interest 50%). Offshore contract areas are: (i) Area C with the Bouri oil field (Eni s interest 50%); and (ii) Area D with Blocks NC 41 and NC 169 (onshore) that feed the Western Libyan Gas Project (Eni s interest 50%).

In the exploration phase, Eni is operator of four onshore blocks in the Kufra area (186/1, 2, 3 & 4) and in the onshore contract Areas A, B and offshore Area D.

Exploration and production activities in Libya are regulated by six Exploration and Production Sharing Agreements (EPSA). The licenses of Eni s assets in Libya expire in 2042 and 2047 for oil and gas properties, respectively.

Tunisia. Eni has been present in Tunisia since 1961. In 2013, Eni s production amounted to 13 KBOE/d. Eni s activities are located mainly in the Southern Desert Areas and in the Mediterranean offshore facing Hammamet.

Exploration and production in this Country are regulated by concessions.

Production mainly comes from operated Maamoura and Baraka offshore Blocks (Eni s interest 49%) and the Adam (Eni operator with a 25% interest), Oued Zar (Eni operator with a 50% interest), Djebel Grouz (Eni operator with a 50% interest), MLD (Eni s interest 50%) and El Borma (Eni s interest 50%) onshore blocks.

Production optimization represents the main activity currently performed in the above listed concessions to mitigate the natural field production decline.

Sub-Saharan Africa

Eni s operations in Sub-Saharan Africa are conducted mainly in Angola, Congo, Mozambique and Nigeria. In 2013, Sub-Saharan Africa accounted for 20% of Eni s total worldwide production of oil and natural gas.

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Angola. Eni has been present in Angola since 1980. In 2013, Eni s production averaged 80 KBOE/d. Eni s activities are concentrated in the conventional and deep offshore.

The main producing blocks with Eni s participation are: (i) Block 0 in Cabinda (Eni s interest 9.8%) North of the Angolan coast; (ii) Development Areas in the former Block 3 (Eni s interest 12%) in the offshore of the Congo Basin; (iii) Development Areas in the Block 14 (Eni s interest 20%) in the deep offshore west of Block 0; (iv) Development Areas in the former Block 15 (Eni s interest 20%) in the deep offshore of the Congo Basin; and (v) Block 15/06 (Eni operator with a 35% interest) with ongoing development activities.

Eni retains interests in other non producing concessions, particularly the Lianzi Development Area (Block 14K/A IMI Unit Area - Eni s interest 10%), Block 35/11 (Eni operator with a 30% interest) and in Block 3/05-A (Eni s interest 12%), onshore Cabinda North (Eni s interest 15%) and the Open Areas of Block 2 awarded to the Gas Project (Eni s interest 20%).

Exploration and production activities in Angola are regulated by concessions and PSAs.

In 2013, the East Hub project was sanctioned in the Block 15/06. The development program includes the drilling of submarine wells that were linked to an FPSO with a capacity of 80 KBOE/d. Peak production of 55 KBOE/d is expected in 2017. Development activities progressed at the West Hub project, with start-up expected at the end of 2014.

In the Block 0, the development activities of the Mafumeira field included the installation of production and treatment platforms and underwater linkage. Start-up is expected by the end of 2015. In the Block 14 KA/IMI, the development activities progressed at the Lianzi field by means of the linkage to the existing production facilities. The second phase of Kizomba satellites in the Development Area of former Block 15 progressed as planned activities. The project provides to put into production three additional discoveries that will be linked to the existing FPSO. Start-up is expected at the end of 2015.

Eni holds a 13.6% interest in the Angola LNG Ltd (A-LNG) consortium responsible for the construction of an LNG plant with a processing capacity of approximately 1.1 BCF/d of natural gas, producing 5.2 mmtonnes/y of LNG and over 50 KBBL/d of condensates and LPG. It envisages the development of 10,594 BCF of gas in 30 years. The LNG plant started up and delivered its first cargo in June 2013.

In addition, Eni is part of the Gas Project, a second gas consortium with the Angolan National Company and other partners that will explore further potential gas discoveries to support the feasibility of a second LNG train or other marketing projects to monetize gas and associated liquids.

Exploration activities yielded positive results in the Block 15/06 with the oil Vandumbu 1 discovery.

In the medium term, management expects to increase Eni s production to approximately 116 KBBL/d reflecting additions from ongoing development projects.

Congo. Eni has been present in Congo since 1968. In 2013, production averaged 107 KBOE/d net to Eni. Eni s activities are concentrated in the conventional and deep offshore facing Pointe-Noire and onshore.

Eni s main operated oil producing interests in Congo are the Zatchi (Eni s interest 65%), Loango (Eni s interest 50%), Ikalou (Eni s interest 100%), Djambala, Foukanda and Mwafi (Eni s interest 35%), Kitina (Eni s interest 65%), Awa Paloukou (Eni s interest 90%), M Boundi (Eni s interest 83%), Kouakouala (Eni s interest 75%), Zingali and Loufika (Eni s interest 85%) fields.

Other relevant producing areas are a 35% interest in the Pointe-Noire Grand Fond, PEX and Likouala permits.

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In the exploration phase, Eni also holds interests in the Marine XII offshore permit (Eni operator with a 65% interest).

In 2013, Eni acquired the operatorship of Ngolo exploration block, which is part of the Cuvette Basin, in the joint venture with the Congolese state company Société Nationale des Pétroles du Congo (SNPC). Exploration activities will take place over a period of 10 years.

During the year, Eni redefined with the relevant authorities the extension of Madingo, Marine VI and Marine VII exploration permits, with the aligning of expiring date within the period 2034-2039, the dilution of Eni s stake and an acquisition interest in new high potential area. The approval of the relevant authorities is in progress.

Exploration and production activities in Congo are regulated by production sharing agreements.

Activities on the M Boundi field moved forward with the application of Eni advanced recovery techniques and a design to monetize associated gas. Gas is sold under long-term contracts to power plants in the area including the CEC - Centrale Electrique du Congo (Eni s interest 20%) with a 300 MW generation capacity. These facilities will also receive in the future gas from the offshore discoveries of the Marine XII permit. In 2013, M Boundi contractual supplies were approximately 106 mmCF/d (approximately 17 KBOE/d net to Eni).

Development program progressed at the Litchendjili sanctioned project in the Block Marine XII. The project provides for the installation of a production platform, the construction of transport facilities and of an onshore treatment plant. The start-up is expected by the end of 2015, with a production plateau of approximately 12 KBOE/d net to Eni. Production will also feed the CEC power station.

Exploration activities yielded positive results in the offshore Block Marine XII with the oil and gas discovery and the appraisal of the Nené Marine field and with the appraisal of gas and condensates Litchendjili discovery.

In the medium term, management expects to increase Eni s production in Congo, with a level of 113 KBOE/d in 2017.

Ghana. Eni has been present in Ghana since 2009 and currently is the operator of the Offshore Cape Three Points (Eni s interest 47.22%) and Offshore Keta Contract Area (Eni s interest 35%) exploration permits.

Exploration activities yielded positive results with the Sankofa East-2A appraisal well, in the Offshore Cape Three Points license. The appraisal program of the oil and gas discoveries was concluded in mid 2013 and negotiations with the local authorities started to move to the Development phase. The start-up of the project is expected by the end of 2016.

Mozambique. Eni has been present in Mozambique since 2006, following the acquisition of the Area 4 Block located in the offshore Rovuma Basin. The exploration period expires in 2015, and a 30-year duration is awarded in respect of any approved Development and Production Area.

In 2011, Eni made the important gas discovery of Mamba.

On July 26, 2013, Eni concluded the sale of a 28.57% interest in Eni East Africa (EEA) to China National Petroleum Corp (CNPC). EEA retains a 70% interest in the Area 4 mineral property, located offshore of Mozambique. CNPC indirectly acquires, through its equity investment in Eni East Africa, a 20% interest in Area 4, while Eni retains operatorship and a 50% interest through the remaining stake. The total consideration was equal to euro 3,386 million, with a gain of equivalent amount recorded in profit and loss (euro 3,359 million, euro 2,994 million net of tax charges).

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The exploration campaign of the year regarded the appraisal of the Mamba and Coral discoveries and a new prospect in the Southern section of Area 4, where in September 2013 Eni made the Agulha discovery. Based on ongoing studies management considers that this exploration area contains a large amount of gas resources.

Nigeria. Eni has been present in Nigeria since 1962. In 2013, Eni s oil and gas production averaged 120 KBOE/d located mainly onshore and offshore the Niger Delta.

In the development/production phase Eni operates onshore Oil Mining Leases (OML) 60, 61, 62 and 63 (Eni s interest 20%); and offshore OML 125 (Eni s interest 85%) and OPL 245 (Eni s interest 50%), holding interests in OML 118 (Eni s interest 12.5%) and in OML 119 and 116 Service Contracts. As partners of SPDC JV, the largest joint venture in the Country, Eni also holds a 5% interest in 22 onshore blocks and a 12.86% interest in 5 conventional offshore blocks.

In the exploration phase Eni operates offshore OML 134 (Eni s interest 85%), OPL 2009 (Eni s interest 49%); and onshore OPL 282 (Eni s interest 90%) and OPL 135 (Eni s interest 48%). Eni also holds a 12.5% interest in OML 135.

Exploration and production activities in Nigeria are regulated mainly by production sharing agreements and concession contracts as well as service contracts, in two blocks, where Eni acts as contractor for state-owned company.

In the OML 125 Block, the Abo - Phase 3 project was started up, with production of approximately 5 KBOE/d net to Eni.

Main activities progressed to support gas production to feed the Bonny liquefaction plant in the OML 28 Block (Eni s interest 5%), within the integrated oil and natural gas project in the Gbaran-Ubie Area, the drilling campaign was completed. The development plan provides for the construction of a Central Processing Facility (CPF) with a treatment capacity of approximately 1 BCF/d of gas and 120 KBBL/d of liquids. Further development phases are planned to put in production the residual mineral potential in the area.

Other activity during the year concerned: (i) the Forkados-Yokri field (Eni s interest 5%). The project includes the drilling of 24 producing wells, the upgrading of existing flowstations and the construction of transport facilities; and

(ii) Bonga NW field in the OML 118 Block. The activities include the drilling and completion of producing and infilling wells.

Eni holds a 10.4% interest in the Nigeria LNG Ltd which runs the Bonny liquefaction plant, located in the Eastern Niger Delta. The plant has a design treatment capacity of approximately 1,236 BCF/y of feed gas corresponding to a production of 22 mmtonnes/y of LNG on six trains. The seventh unit is being engineered as it is in the planning phase. When fully operational, total capacity will amount to approximately 30 mmtonnes/y of LNG, corresponding to a feedstock of approximately 1,624 BCF/y. Natural gas supplies to the plant are provided under gas supply agreements with a 20-year term from the SPDC joint venture (Eni s interest 5%) and the NAOC JV, the latter operating the OMLs 60, 61, 62 and 63 Blocks with an overall amount of 2,825 mmCF/d (268 mmCF/d net to Eni corresponding to approximately 49 KBOE/d). LNG production is sold under long-term contracts and exported to European and American markets by the Bonny Gas Transport fleet, wholly owned by Nigeria LNG Co.

Eni holds a 17% interest in Brass LNG Ltd Co for the construction of a natural gas liquefaction plant to be built near the existing Brass terminal, 100 kilometers west of Bonny. This plant is expected to start with a production capacity of 10 mmtonnes/y of LNG corresponding to 590 BCF/y (approximately 45 net to Eni) of feed gas on two trains for twenty years. Supply to this plant will derive from the collection of associated gas from nearby producing fields and from the development of gas reserves in the onshore OMLs 60 and 61.

In the medium term, management expects to increase Eni s production in Nigeria to approximately 160 KBOE/d, reflecting the development of gas reserves.

Kazakhstan

Eni has been present in Kazakhstan since 1992. Eni is co-operator of the Karachaganak field and partner in the North Caspian Sea Production Sharing Agreement (NCSPSA). In 2013, Eni s operations in Kazakhstan accounted for 6% of its total worldwide production of oil and natural gas.

Kashagan. Eni holds a 16.81% working interest in the North Caspian Sea Production Sharing Agreement. The NCSPSA defines terms and conditions for the exploration and development of the Kashagan field which was discovered in the Northern section of the contractual area in the year 2000 over an undeveloped area extending for 4,600 square kilometers. Management believes this field contains a large amount of hydrocarbon resources which will eventually be developed in phases. The NCSPSA will expire at the end of 2041.

The participating interest in the NCSPSA has been redefined, effective as of January 1, 2008, in line with an agreement signed in October 2008 with Kazakh Authorities which proportionally diluted the participating interest of the international companies by transferring a 10% stake in the project to the Kazakh national oil company, KazMunaiGas. In addition to Eni, the partners of the Consortium are the Kazakh national oil company, KazMunaiGas, with a participating interest of 16.88%, the international oil companies Total, Shell and ExxonMobil, each with a participating interest currently of 16.81%, CNCP with 8.33%, and Inpex with 7.56%.

The exploration and development activities of the Kashagan field and the other discoveries made in the contractual area are executed through an operating model which entails an increased role of the Kazakh partner and defines the international parties responsibilities in executing the subsequent development phases of the project once they are sanctioned. The North Caspian Operating Co (NCOC) BV, participated by the seven partners of the consortium has taken over the operatorship of the project. Subsequently development, drilling and production activities have been delegated by NCOC BV to the main partners of the Consortium: Eni has retained the responsibility for the development of Phase 1 of the project (the so-called "Experimental Program") and, when sanctioned, the onshore part of Phase 2.

On May 23, 2012, the Consortium partners and the Authority of the Republic of Kazakhstan signed an agreement to amend the sanctioned development plan at the Experimental Program of the Kashagan field (Amendment 4) which included an update to the project schedule, a revision of investment estimates and a settlement agreement of all pending claims relating to recoverable costs and other tax matters. The amendment also included a commercial framework to supply a share of the natural gas produced from Kashagan to the domestic market and an agreement whereby the international partners of the Consortium shall finance the share of project cost to be borne by the Kazakh KMG partner, in excess to the amounts sanctioned in the original budget costs (Amendment 3).

On September 11, 2013, following the completion, test and delivery of all infrastructures, the first oil from the giant Kashagan field was produced.

From October 2013, production has been halted due to a technical issue that occurred to the pipeline transporting acid gas from offshore to onshore facilities, without any impact on the environment and local communities. Recovery activities are ongoing. Management believes that from 2015 field production will recover to the originally expected level and the field contribution to Eni s production profile for the year 2014 has been prudently assumed to be marginal.

The Phase 1 (Experimental Program) is targeting an initial production capacity of 150 KBBL/d; when the second treatment train and compression facilities for gas re-injection will be completed and put online enabling to increase the production capacity up to 370 KBBL/d. The partners are planning to further increase available production capacity up to 450 KBBL/d by installing additional gas compression capacity for re-injection in the reservoir. The partners submitted the scheme of this additional phase to the relevant Kazakh Authorities.

In 2013, Eni submitted the development program of the Western section of the nearby Kalamkas discovery to the authorities. Sanction is expected in 2014 to start up with the FEED phase.

Management believes that significant capital expenditures will be required in case the partners of the venture would sanction a second development phase and possibly other additional phases. Eni will fund those investments in proportion to its participating interest of 16.81%. However, taking into account that future development expenditures will be incurred over a long time horizon and subsequent to the production start-up, management does not expect any material impact on the Company s liquidity or its ability to fund these capital expenditures. In addition to the expenditures for developing the field, further capital expenditures will be required to build the infrastructures needed for exporting the production to international markets.

As of December 31, 2013, Eni s proved reserves booked for the Kashagan field amounted to 565 mmBOE, barely unchanged from 2012.

As of December 31, 2012, Eni s proved reserves booked at the Kashagan field amounted to 568 mmBOE, recording an increase compared to 2011 reflecting the settlement agreement signed with Kazakh Authority whereby Eni will be able to produce and market volumes of natural gas from Kashagan.

As of December 31, 2011, Eni s proved reserves booked for the Kashagan field amounted to 449 mmBOE, recording a decrease of 120 mmBOE compared to 2010 mainly due to a higher Brent marker price and downward revisions.

As of December 31, 2013, the aggregate costs incurred by Eni for the Kashagan project capitalized in the financial statements amounted to $8.2 billion (euro 5.9 billion at the EUR/USD exchange rate of December 31, 2013). This capitalized amount included: (i) $6.1 billion relating to expenditure incurred by Eni for the development of the oilfield; and (ii) $2.1 billion relating primarily to accrue finance charges and expenditures for the acquisition of interests in the North Caspian Sea PSA Consortium from exiting partners upon exercise of pre-emption rights in previous years.

As of December 31, 2012, the aggregate costs incurred by Eni for the Kashagan project capitalized in the financial statements amounted to $7.5 billion (euro 5.7 billion at the EUR/USD exchange rate of December 31, 2012). This capitalized amount included: (i) $5.7 billion relating to expenditure incurred by Eni for the development of the oilfield; and (ii) $1.8 billion relating primarily to accrue finance charges and expenditures for the acquisition of interests in the North Caspian Sea PSA Consortium from exiting partners upon exercise of pre-emption rights in previous years.

Karachaganak. Located onshore in West Kazakhstan, Karachaganak is a liquid and gas field. Operations are conducted by the Karachaganak Petroleum Operating consortium (KPO) and are regulated by a PSA lasting 40 years, until 2037. Eni and British Gas are co-operators of the venture. On June 28, 2012, the international Contracting Companies of the Final Production Sharing Agreement of the giant Karachaganak gas-condensate field and the Republic of Kazakhstan closed a settlement agreement of all pending claims relating to the recovery of costs incurred to develop the field and certain tax matters. Eni s interest in the Karachaganak project is 29.25%.

In 2013, production of the Karachaganak field averaged 250 KBBL/d of liquids (61 net to Eni) and 865 mmCF/d of natural gas (195 net to Eni). This field is developed by producing liquids from the deeper layers of the reservoir and re-injecting the associated gas in the higher layers. Approximately 90% of liquid production are stabilized at the Karachaganak Processing Complex (KPC) with a capacity of approximately 250 KBBL/d and exported to Western markets through the Caspian Pipeline Consortium

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(Eni s interest 2%) and the Atyrau-Samara pipeline. The remaining volumes of non-stabilized liquid production and associated raw gas not re-injected in the reservoir are marketed at the Russian terminal in Orenburg.

The expansion project of the Karachaganak field is currently under study. The project is aimed for a further developing gas and condensates reserves by means of the installation, in stages, of gas treatment plants and re-injection facilities to support liquids production plateau and increase gas sales. The development plan is currently in the phase of technical and marketing discussion to be presented to the relevant authorities, with FEED expected in 2014.

As of December 31, 2013, Eni s proved reserves booked for the Karachaganak field amounted to 470 mmBOE, barely unchanged from 2012.

As of December 31, 2012, Eni s proved reserves booked for the Karachaganak field amounted to 473 mmBOE, reporting a slightly decrease from 2011 deriving mainly from the divestment of Eni s stake in the project, partly offset by upwards revisions.

As of December 31, 2011, Eni s proved reserves booked for the Karachaganak field amounted to 500 mmBOE based on a 32.5% working interest, corresponding to the pre-divestment share. The 57 mmBOE decrease derives from the price effect and production of the year in part compensated for upwards revisions.

Rest of Asia

In 2013, Eni s operations in the rest of Asia accounted for 9% of its total worldwide production of oil and natural gas.

China. Eni has been present in China since 1984 with activities located in the South China Sea. In 2013, Eni s production amounted to 7 KBOE/d.

Exploration and production activities in China are regulated by production sharing agreements.

In March 2013, Eni and CNPC signed a joint study agreement for the development of shale gas resources in the Rongchangbei Block which covers an area of approximately 2,000 square kilometers, located in the Sichuan Basin.

In 2013, hydrocarbons were produced from the offshore Blocks 16/08 and 16/19 through eight platforms connected to an FPSO. Natural gas production from the HZ21-1 field was delivered through a sealine to the Zhuhai Terminal and sold to the Chinese National Oil Co CNOOC. Oil was mainly produced from the HZ25-4 field (Eni s interest 49%). Activity was operated by the CACT-Operating Group (Eni s interest 16.33%). In December 2013, the Block 16/08 PSC is expired.

India. Eni has been present in India since 2005 and its activities are located in the offshore Cauvery Basin near the South-Eastern coast. In 2013, Eni s production amounted to 1 KBOE/d.

Production mainly comes from the PY-1 gas field which is operated by Eni s subsidiary Hindustan Oil

Exploration Co Ltd (Eni s interest 47.18%). Gas production is sold to the National oil company.

Indonesia. Eni has been present in Indonesia since 2001. In 2013, Eni s production mainly composed of gas, amounted to 13 KBOE/d. Activities are concentrated in the Eastern offshore and onshore of East Kalimantan, offshore Sumatra, and offshore and onshore of West Timor and West Papua; in total, Eni holds interests in 13 blocks.

Exploration and production activities in Indonesia are regulated by PSAs.

Development activities progressed at the operated Jangkrik (Eni s interest 55%) and Jau (Eni s interest 85%) offshore fields. The Jangkrik project includes linkage of production wells to a Floating Production Unit for gas and

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condensate treatment and the construction of a transportation facility to the Bontang liquefaction plant. Start-up is expected in 2017 with a production peak of 80 KBOE/d (42 KBOE/d net to Eni) in 2018. The Jau project provides for the drilling of production wells and the linkage to onshore plants via pipeline. Start-up is expected in 2017.

Development activities are underway at the Indonesia Deepwater Development project (Eni s interest 20%), located in the East Kalimantan, to ensure gas supplies to the Bontang plant. The project initially provides for the linkage of the Bangka field to existing facilities, with start-up expected in 2016. Then the project also provides for the integrated development of the first Hub including the Gendalo, Gandang, Maha fields and the second Hub of the Gehem field. Start-up is expected in 2018.

Iran. Eni has been operating in Iran for several years under four Service Contracts (South Pars, Darquain, Dorood and Balal, these latter two projects being operated by another international oil company) entered into with the National Iranian Oil Co (NIOC) between 1999 and 2001, and no other exploration and development contracts have been entered into since then. All above mentioned projects have been completed or substantially completed; the last one, the Darquain project, is being handed over to NIOC. Operatorship had already been transferred to a NIOC affiliate in 2010. When the final hand over of operations will be completed, Eni s involvements will essentially consist of being reimbursed for its past investments. In 2013, Eni s contractual reimbursements were equivalent to a production of 4 KBOE/d, lower than 1% of the Group s worldwide production. Eni does not believe that its activities in Iran have a material impact on the Group s results. See "Item 3 Risk factors Political considerations Iran" for a full discussion of risks involved by our presence in Iran.

Iraq. Eni has been present in Iraq since 2009. Eni, leading a consortium of partners including international companies and the national oil company Missan Oil, holds 41.6% interests in Zubair oilfield.

Development and production activities in Iraq are regulated by Technical Service Contract. This contractual term establishes an oil entitlement mechanism and associated risk profile similar to those applicable in production sharing contracts.

In July 2013, Eni signed with the national oil company South Oil Co and the Iraqi Ministry of Oil an amendment to the Technical Service Contract for the development of the Zubair oilfield. The agreement includes a new target plateau at 850 KBBL/d and extends an expiring date of service contract for an additional five years, until 2035.

In 2013, production of the Zubair field averaged 306 KBBL/d (22 KBBL/d net to Eni).

Pakistan. Eni has been present in Pakistan since 2000. In 2013, Eni s production mainly composed of gas amounted to 50 KBOE/d.

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Exploration and production activities in Pakistan are regulated by concessions (onshore) and PSAs (offshore).

Eni s main permits in the Country are Bhit/Bhadra (Eni operator with a 40% interest), Sawan (Eni s interest 23.68%) and Zamzama (Eni s interest 17.75%), which in 2013 accounted for 75% of Eni s production in Pakistan.

Exploration activities yielded positive results with the onshore gas discovery of Lundali 1 in the Sukhpur concession (Eni operator with a 45% interest) and with the gas discovery of Bhadra North-2.

Russia. Eni sold to Llc Yamal Development (joint venture of JSC Novatek and JSC Gazprom Neft) its 60% interest in Artic Russia. Artic Russia owns a 49% stake of Severenergia, which holds four licenses for the exploration and production of hydrocarbons in the Region of Yamal Nenets (Siberia), among which in particular the on-stream field of Samburgskoye, Eni s first development in the Russian upstream, with a production of 29 KBOE/d in 2013. The consideration for the disposal, equal to euro 2.16 billion ($2,940 million), was cashed in on January 15, 2014.

In June 2013, Eni and Rosneft signed the completion deed relating to the agreements for the joint development of exploration activities in the Russian Barents Sea (Fedynsky and Central Barents licenses, Eni s interest 33.33%) and in the Black Sea (Western Chernomorsky license, Eni s interest 33.33%).

Turkmenistan. Eni started its activities in Turkmenistan with the purchase of the British company Burren Energy plc in 2008. Activities are focused in the Western part of the Country. In 2013, Eni s production averaged 9 KBOE/d.

Exploration and production activities in Turkmenistan are regulated by PSAs.

Eni is operator of the Nebit Dag producing Block (with a 100% interest). Production derives mainly from the Burun oilfield. Oil production is shipped to the Turkmenbashi refinery plant. Eni receives, by means of a swap with the Turkmen Authorities, an equivalent amount of oil at the Okarem terminal, close to the South coast of the Caspian Sea. Eni s entitlement is sold FOB. Associated natural gas is used for own consumption and gas lift system. The remaining amount is delivered to Turkmenneft, via national grid.

Vietnam. Eni has been present in Vietnam since June 2012 actually with the operatorship of three exploration Blocks 105-110/04, 114 and 120 (Eni s interest 50%), located offshore Vietnam, in the Song Hong and Phu Khanh Area.

In January 2013, Eni and the Vietnamese national oil company PetroVietnam signed a Memorandum of Understanding for the development of business opportunities in Vietnam and abroad.

In February 2013, Eni signed an agreement with PetroVietnam, for the joint evaluation of unconventional resources in the Country.

Americas

In 2013, Eni s operations in Americas area accounted for 7% of its total worldwide production of oil and natural gas.

Ecuador. Eni has been present in Ecuador since 1988. Operations are performed in Block 10 (Eni s interest 100%) located in the Oriente Basin, in the Amazon forest. In 2013, Eni s production averaged 13 KBBL/d.

Exploration and production activities in Ecuador are regulated by a service contract, due to expire in 2023.

Production deriving solely from the Villano field is processed by means of a Central Production Facility and transported via a pipeline network to the Pacific coast.

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Trinidad and Tobago. Eni has been present in Trinidad and Tobago since 1970. In 2013, Eni s production averaged 59 mmCF/d and its activity is concentrated offshore North of Trinidad.

Exploration and production activities in Trinidad and Tobago are regulated by PSAs.

Production is provided by the Chaconia, Ixora, Hibiscus, Ponsettia, Bougainvillea and Heliconia gas fields in the North Coast Marine Area 1 Block (Eni s interest 17.3%). Production is supported by two fixed platforms linked to the Hibiscus processing facility. Natural gas is used to feed trains 2, 3 and 4 of the Atlantic LNG liquefaction plant on Trinidad s coast and sold under long-term contracts. LNG production is mainly sold in the United States. Additional cargoes are sent to alternative destinations on a spot basis.

United States. Eni has been present in the United States since 1968. Activities are performed in the conventional and deep offshore in the Gulf of Mexico, onshore and offshore in Alaska, and more recently in Texas onshore.

In 2013, Eni s oil and gas production mainly derived from the Gulf of Mexico with an average of 80 KBOE/d.

Exploration and production activities in the United States are regulated by concessions.

Eni holds interests in 228 exploration and production blocks in the Gulf of Mexico of which 139 are operated by Eni.

The main fields operated by Eni are Allegheny, Appaloosa and Morpeth (Eni s interest 100%), Longhorn-Leo, Devils Towers and Triton (Eni s interest 75%) as well as Pegasus (Eni s interest 58%). Eni also holds interests in the Medusa (Eni s interest 25%), Europa (Eni s interest 32%) and Thunder Hawk (Eni s interest 25%) fields.

In order to achieve the highest security standards of operations, Eni entered the HWCG Consortium of Gulf of Mexico operators. The HWGC provides resources, coordination and performs certain activities associated with underwater containment of erupting wells, evacuation of hydrocarbon on the sea surface, storage and transport to the coastline. For further information on this matter see "Item 3 Risk factors".

In March 2013, Eni was the highest bidder in five offshore exploration blocks located in the Mississippi Canyon and Desoto Canyon areas within the Central Gulf of Mexico Lease Sale 227. Relevant authorities approved the bid of one of five blocks.

In November 2013, Eni signed an agreement with the American company Quicksilver, for explorating and developing an area with unconventional oil reservoirs (shale oil), onshore the United States. Eni is expected to acquire a 50% interest in the Leon Valley area (West Texas). The work plan provides for the drilling of up to five exploration wells, aiming at determining the hydrocarbon potential of the area and the subsequent development plan. Eni will invest up to $52 million, for the completion of the project s exploration activities. The agreement also establishes that Eni will obtain 50% of another area located in the Leon Valley, without additional costs.

Phase 1 of the development plan was sanctioned at the Heidelberg field (Eni s interest 12.5%) in the deep offshore of the Gulf of Mexico. The project provides for the drilling of 5 producing wells and the installation of a producing platform. Start-up is expected at the end of 2016 with a production of approximately 9 KBOE/d net to Eni.

Development activities in the Gulf of Mexico mainly concerned: (i) drilling and completion activities at the Hadrian South (Eni s interest 30%), Lucius/Hadrian North (Eni s interest 5.4%) and St. Malo (Eni s interest 1.25%) fields; (ii) infilling activities at the producing operated Appaloosa (Eni s interest 100%), Longhorn (Eni s interest 75%), Pegasus (Eni s interest 58%) fields and at the non-operated Front Runner field (Eni s interest 37.5%); and (iii) maintenance of the pipeline linking to the Corral production platform.

Eni holds interests in 102 exploration and development blocks in Alaska, with interests ranging from 10 to 100% and for 49 of these blocks, Eni is the operator.

The main fields are Nikaitchuq (Eni operator with a 100% interest) and Oooguruk (Eni s interest 30%) with an overall production of approximately 12 KBBL/d net to Eni in 2013.

Development activities mainly concerned drilling activities at the Nikaitchuq and Oooguruk fields.

Venezuela. Eni has been present in Venezuela since 1998. In 2013, Eni s production averaged 10 KBBL/d.

Activity is concentrated in the Gulf of Venezuela, in the Gulfo de Paria and onshore in the Orinoco Oil Belt.

Exploration and production of oilfields are regulated by the terms of the so-called Empresa Mixta. Under the new legal framework, only a company incorporated under the law of Venezuela is entitled to conduct petroleum operations. A stake of at least 60% in the capital of such company is held by an affiliate of the Venezuela state oil company, PDVSA, preferably Corporación Venezuelana de Petróleo (CVP).

In March 2013, production (accelerated early production) started up at the Junin 5 field (Eni s interest 40%), located in the Orinoco oil belt and containing 35 BBBL of certified heavy oil in place. Early production of the first phase is expected to reach a plateau of 75 KBBL/d by the end of 2015, targeting a long-term production plateau of 240 KBBL/d. The project provides for the construction of a refinery with a capacity of approximately 350 KBBL/d. Eni agreed to finance part of PDVSA s development costs for the early production phase and engineering activity of refinery plant up to $1.74 billion. Drilling activities and installation of the transport and treatment facilities are ongoing.

The sanctioned development plan progressed at the Perla gas discovery, located in the Cardon IV Block (Eni s interest 50%), in the Gulf of Venezuela. PDVSA exercised its 35% back-in right. Eni will retain the 32.5% joint controlled interest in the company, at the execution of the transfer stake. The early production phase includes the utilization of the existing discovery/appraisal wells and the installation of production platforms linked by pipelines to the onshore treatment plant. Target production of approximately 450 mmCF/d is expected in 2015. The development program will continue with the drilling of additional wells and the upgrading of treatment facilities to reach a production plateau of approximately 1,200 mmCF/d.

Eni also holds a stake in the Corocoro field (Eni s interest 26%), in the Gulfo de Paria, with a production of 37 KBOE/d in 2013.

Eni is also participating with a 19.5% interest in the Gulfo de Paria Centrale offshore oil exploration block, where the Punta Sur oil discovery is located and with a 40% interest in Punta Pescador and Gulfo de Paria Ovest.

Australia and Oceania

Eni s operations in Australia and Oceania area are conducted mainly in Australia. In 2013, the area of Australia and Oceania accounted for 2% of Eni s total worldwide production of oil and natural gas.

Australia. Eni has been present in Australia since 2001. In 2013, Eni s production of oil and natural gas averaged 29 KBOE/d. Activities are focused on conventional and deep offshore fields.

Exploration and production activities in Australia are regulated by concession agreements, whereas in the cooperation zone between Timor Leste and Australia (Joint Petroleum Development Area - JPDA) they are regulated by PSAs.

The main production blocks in which Eni holds interests are WA-33-L (Eni s interest 100%), JPDA 03-13 (Eni s interest 10.99%) and JPDA 06-105 (Eni operator with a 40% interest). In the appraisal and development phase Eni holds interests in NT/P68 (Eni s interest 50%) and NT/P48 (Eni s interest 32.5%). In addition, Eni holds interest in 7 exploration licenses, of which 1 in the JPDA.

Exploration activities yielded positive results in the NT/P48 permit located in the Timor Sea, with the Evans Shoal North-1 discovery.

Capital expenditures

See "Item 5 Liquidity and capital resources Capital expenditures by segment".

Disclosure pursuant to Section 13(r) of the Exchange Act

The Iran Threat Reduction and Syria Human Rights Act of 2012 (ITRA) created a new subsection (r) in Section 13 of the Exchange Act which requires a reporting issuer to provide disclosure if the issuer or any of its affiliates engaged in certain enumerated activities relating to Iran, including activities involving the Government of Iran. Disclosure responsive to this requirement is presented under Item 3 Political considerations Risks associated with our presence in sanction targets and below in this section.

In accordance with our general business principles and Code of Ethics, Eni seeks to comply with all applicable international trade laws including applicable sanctions and embargoes.

The activities referred to below have been conducted outside the U.S. by non-U.S. Eni subsidiaries. For purposes of the disclosure below, amounts have been converted into U.S. dollars at the average or spot exchange rate, as appropriate. We do not believe that any of the transactions or activities listed below violated U.S. sanctions also considering the waiver that we were granted by relevant U.S. Authorities, including the U.S. Department of State, in relation to certain Iran-related activities. For more information please refer to Item 3 Risk factors Political considerations Risks associated with our presence in sanction targets .

As described in more detail under Item 3 Risk factors Political considerations Risks associated with our presence in sanction targets , in 2013, Eni carried out support activities and services in respect of certain oil fields in Iran pursuant to certain legacy Service Contracts. Eni s operating expenses pursuant to those contracts in 2013 amounted to approximately $2 million. In addition, in connection with its remaining Iranian operations, in 2013 Eni paid approximately $4 million for social security, withholding tax, corporate tax and rental tax.

In 2013, Eni s production in Iran averaged 4 KBOE/d, representing less than 1% of the Eni s total production for the year. We booked revenues of $130 million in 2013 in connection with our share of equity production and we reported a net profit of $26 million at our Iranian operations. As of the balance sheet date Eni had outstanding trade receivables amounting to $323 million towards Iranian oil national companies which were recorded in connection with revenues recognized in 2013 and in previous reporting periods. In 2013, we collected cash payments for a total of $74 million. Those revenues and trade receivables related to the recovery of the costs incurred by Eni in its performance of petroleum projects, mainly pertaining to the ongoing Darquain project as disclosed under Item 3 Risk factors Political considerations Risks associated with our presence in sanction targets . We had no payables towards Iranian national oil companies as of the balance sheet date. We had a payable amounting to $27 million relating to health and social security insurance due to the Iranian Social Security Organization, which will be settled upon termination of our oil projects.

Eni Exploration & Production projects in Iran are currently in the cost recovery phase. Therefore, Eni has ceased making any further investment in the country and is not planning to make additional capital expenditures in Iran in future years.

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Gas & Power

Eni s Gas & Power segment engages in supply, trading and marketing of gas and electricity, international transport, and LNG supply and marketing. This segment also includes the activities of electricity generation. In 2013, Eni s worldwide sales of natural gas amounted to 93.17 BCM, including 2.61 BCM of gas sales made directly by Eni s Exploration & Production segment. Sales in Italy amounted to 35.86 BCM, while sales in European markets were 47.35 BCM that included 4.67 BCM of gas sold to certain importers to Italy.

In 2012, following the divestment of a significant interest in Snam, Eni lost control on activities related to the transport, re-gasification, storage and distribution of natural gas in Italy.

Marketing of natural gas

The outlook in the European gas sector remains challenging as the current economic downturn will weigh on the prospects of a solid recovery in gas demand, while we expect strong competitive pressure fuelled by a supply overhang. Management expects that continuing margin pressures will erode the business s profitability in 2014 and beyond, particularly in the Italian market. A weaker-than-anticipated demand growth over the foreseeable future and rising competitive pressures fuelled by ongoing oversupplies in the European market will reduce sales opportunities and trigger pricing competition also fuelled by rigidities at long-term supply contracts with take-or-pay clauses. In fact, we expect that minimum collection obligations in connection with take-or-pay, long-term gas supply contracts and the necessity to minimize the associated financial exposure will force gas operators to compete more aggressively on pricing in consideration of lower selling opportunities, with negative effects on selling prices and profitability. Unit margins are expected to remain under pressure due to depressed spot prices at continental hubs which have become the contractual benchmark in selling formulas in all of our markets of operations. In addition, as long as the cost of gas supplies to the Group remains indexed to oil prices, the Company will be exposed to the risk of rising oil prices. In Italy, we expect that gas margins will continue on a downward trends following the sharp contraction registered in 2013 due to falling spot prices. We expect that a number of negative catalysts will continue to affect on gas selling prices in Italy including weak demand, an ongoing shift to index selling prices to hub benchmarks at large client segments, competitive pressure which will be fuelled by the current level of minimum take volumes at Italian operators which are well above market dimension, and finally the new measures that have been enacted by the Italian market regulator to cut gas tariffs to residential customers by changing the oil-linked indexation mechanism of the raw material to a new hub-base indexation. See also the other risk factors described in Item 3. These drivers will substantially reduce spot prices in the Italian market and negatively impact the profitability at our Italian operations. Against this scenario the Company set the following priorities: preserve the operating cash flow during the worst phase of the downturn which is expected to continue well in 2014 and recover the profitability in subsequent years leveraging contract renegotiations, a renewed focus on those market segment where we expect to be profitable such as in LNG international sales and a number of measures to streamline our operations, rationalize logistics, improve efficiency and cut costs. The main driver to recover profitability in the Company s gas marketing business is the renegotiation of pricing and other conditions of our supply contracts. In fact, take-or-pay supply contracts include revisions clauses providing for the periodic renegotiation of key economic terms and other conditions based on ongoing changes in the gas market. As of December 31, 2013, management has succeeded in renegotiating about 85% of the Company s long-term portfolio and achieved a reduction in the purchase costs and an improvement in contractual flexibility targeting to mitigate the take or-pay risk. However, management believes that the Company needs to achieve a new round of renegotiation in order to fully align its purchase costs to the current markets conditions. Early in 2014, we signed a Memorandum of Understanding with one of our suppliers which we believe to be an important step towards our objective. We believe that when our supply costs will be aligned to the spot benchmarks quoted in European gas hubs the Company will be able to return to profitability. The Company intends to boost sales to business clients, including utilities, large industrial accounts and medium and small enterprises, leveraging the Company s multiple presence across various markets and expertise in delivering innovative and tailor-made offering structures to best suit customers needs by providing complex pricing formulas with flexibility on volumes and different ways to manage pricing. The other leg of the Company s marketing effort will address retail customers across Europe targeting to enhance the ongoing strong customer base. The drivers to achieve this will be a strategy of customer retention centered on brand identity, a distinctive offer and competitive cost to serve; a wide range of sale channels and continuing innovation in processes, promotion and customer care and post sale assistance. The international expansion in the LNG business is expected to continue by boosting the Company s presence in the more lucrative Far East markets. Finally we plan to achieve costs reduction by streamlining our operations, rationalizing the logistic activities and improving efficiency in selling and general departments. Based on the above outlined trends and industrial actions, management believes that profitability in the Company s gas marketing business will gradually recover along the plan period, albeit the visibility into future results of operations is constrained by the ongoing volatility in marketing margins. Our profitability outlook factors in the expected benefits of ongoing renegotiations at the Company long-term supply contracts, as well as the other risk factors described in Item 3. For a description of uncertainties and risks associated with this strategy see Item 3 Risk factors and Item 5 Operating and financial review and prospects .

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The matters regarding future natural gas demand and sales target discussed in this section and elsewhere herein are forward-looking statements that involve risks and uncertainties that could cause the actual results to differ materially from those in such forward-looking statements. Such risks and uncertainties relating to future natural gas demand include changes in underlying economic factors, changes in regulation, population growth or shrinkage, changes in the relative mix of demand for natural gas and its principal competing fuels, and unexpected developments in the markets for natural gas and its principal competing fuels.

Demand and supply outlook

In 2013, gas demand in Europe continued to fall across Europe (down by 6% in Italy and by 1% on average in most of the European markets) due to declining consumption in all market segments on the back of the economic downturn. The power generation segment recorded the steepest fall, hit by an ongoing expansion in the use of renewable sources and a shift to coal as feedstock for power plants due to cost advantages. Due to the severity of the contraction in European gas demand and ongoing uncertainties in the macroeconomic outlook, management has revised down its projections of gas demand over the medium to long term to factor in a number of trends:

- uncertainties and volatility in the current macroeconomic cycle;
- growing adoption of consumption patterns and life-styles characterized by wider sensitivity to energy efficiency;
- EU policies intended to reduce greenhouse gas (GHG) emissions and promoting renewable energy sources, following prescriptions set by the Climate Change and Renewable Energy package (the so-called PEE 20-20-20). The package includes a commitment to reduce GHG emissions by 20% by 2020 compared to emission levels recorded in 1990 (the target being 30% if an international agreement is reached), as well as improved energy efficiency within the EU Member States of 20% by 2020 and a 20% renewable energy target by 2020. Furthermore, the Energy Roadmap to 2050 set a target of reducing the level of carbon emissions made in 1990 by 80 to 95%; and
- uncertainties about the role of natural gas-fired electricity production.

Management now expects EU demand to remain stable around current levels till 2017 at about 488 BCM, and gas demand in Italy to remain at the current level of 70-72 BCM. These targets are well below the level of gas consumption registered in 2008 by approximately 50 and 15 BCM, respectively, which reflects the real demand destruction that has occurred throughout the downturn.

There might be favorable developments which could support a demand recovery. For example, ongoing changes in the energy policies of the Euro-zone and other important countries like Japan and Taiwan, also as a result of the nuclear accident at the Fukushima plant in Japan, could accelerate a recovery in gas consumption. In addition, the fiscal policies of the EU Member States could affect the composition of the energy mix through the introduction of penalties on the use of the most inefficient and pollutant sources in energy production. Examples of these trends are a proposed European directive to enact a carbon tax to be levied on those sectors which do not participate in the ETS mechanism as well as a proposal to enact certain fiscal adjustments to put a floor to the price of carbon dioxide emissions in the United Kingdom. On the supply-side, gas availability will remain abundant as large investments to upgrade import pipelines to Europe have come online from Russia and Algeria. These include the Medgaz pipeline connecting Algeria to the Iberian Peninsula, the North Stream pipeline connecting Russia to Germany through the Baltic Sea as well as new LNG facilities. Further 27 BCM of new supplies will be secured by a second line of the North Stream in the next future and new storage capacity will come online. In Italy, the gas offer will grow moderately in the next future as a new LNG plant is expected to start operations at Livorno with a 4 BCM treatment capacity and effects are in force of Law Decree No. 130/2010 concerning storage capacity (see below) which is expected to increase by 4 BCM by 2015. Large availability of LNG on a worldwide scale has found an outlet at the European continental hubs driving the development of very liquid spot gas markets driven by the ramp-up of important upstream projects which added an estimated 65 BCM of liquefaction capacity in the 2008-2010 period. Adding to the supply overhang, the discovery and development of large deposits of shale gas ("the shale gas revolution") in the United States has progressively reduced the Country s dependence on LNG imports. In addition, U.S. Authorities have been releasing authorizations to re-convert idle LNG re-gasification terminals located along the Gulf of Mexico coastline into liquefaction terminals to improve the export capacity of gas of the country. Finally we expect that a number of large new upstream projects will fuel new streams of global LNG supplies beyond the plan period. As a result of those drivers, we expect that current market imbalances in Europe will continue over the foreseeable future.

Supply of natural gas

In 2013, Eni s consolidated subsidiaries supplied 85.67 BCM of natural gas, representing a decrease of 1.02 BCM, or 0.8% from 2012. Gas volumes supplied outside Italy (78.52 BCM from consolidated companies), imported in Italy or sold outside Italy, represented approximately 92% of total supplies, substantially in line with 2012 (down 0.62 BCM, or 0.8%) due to higher volumes purchased in Russia (up 9.76 BCM) and the Netherlands (up 1.09 BCM), entirely offset by lower volumes purchased in particular in Algeria (down 5.14 BCM), Norway (down 2.97 BCM) and Libya (down 0.77 BCM). Supplies in Italy (7.15 BCM) slightly decreased from 2012 due to the decline of mature fields. In 2013, main gas volumes from equity production derived from: (i) Italian gas fields (6.1 BCM); (ii) Libyan fields (1.7 BCM); (iii) certain Eni fields located in the British and Norwegian sections of the North Sea (1.5 BCM); (iv) the United States (1.2 BCM); and (v) other European areas (Croatia with 0.4 BCM). Considering also direct sales of the Exploration & Production Division and LNG supplied from the Bonny liquefaction plant in Nigeria, supplied gas volumes from equity production were approximately 16 BCM representing 17% of total volumes available for sale.

The table below sets forth Eni s purchases of natural gas by source for the periods indicated.

Natural gas supply	**2011**	**2012**	**2013**
		(BCM)	
Italy	**7.22**	**7.55**	**7.15**
Outside Italy	**76.05**	**79.14**	**78.52**
Russia	*21.00*	*19.83*	*29.59*
Algeria (including LNG)	*13.94*	*14.45*	*9.31*
Libya	*2.32*	*6.55*	*5.78*
the Netherlands	*11.02*	*11.97*	*13.06*
Norway	*12.30*	*12.13*	*9.16*
the United Kingdom	*3.57*	*3.20*	*3.04*
Hungary	*0.61*	*0.61*	*0.48*
Qatar (LNG)	*2.90*	*2.88*	*2.89*
Other supplies of natural gas	*6.16*	*5.43*	*3.63*
Other supplies of LNG	*2.23*	*2.09*	*1.58*
Total supplies of subsidiaries	**83.27**	**86.69**	**85.67**
Withdrawals from (input to) storage	1.79	(1.35)	(0.58)
Network losses, measurement differences and other changes	(0.21)	(0.28)	(0.31)
Volumes available for sale of Eni s subsidiaries	**84.85**	**85.06**	**84.78**
Volumes available for sale of Eni s affiliates	**9.05**	**7.53**	**5.78**
E&P volumes	**2.86**	**2.73**	**2.61**
Total volumes available for sale	**96.76**	**95.32**	**93.17**

In order to secure long-term access to gas availability, particularly with a view to supplying the Italian gas market, Eni has signed a number of long-term gas supply contracts with key producing countries that supply the European gas markets. These contracts have been ensuring approximately 80 BCM of gas availability from 2010 (including the Distrigas portfolio of supplies and excluding Eni s other subsidiaries and affiliates) with a residual life of approximately 14 years and a pricing mechanism that indexed to the cost of gas to the price of crude oil and its derivatives (gasoil, fuel oil, etc.). These contracts provide take-or-pay clauses whereby the Company is required to collect minimum pre-determined volumes of gas in each year of the contractual term or, in case of failure, to pay the whole price, or a fraction of that price, applied to uncollected volumes up to the minimum contractual quantity. The take-or-pay clause entitles the Company to collect pre-paid volumes of gas in later years during the period of contract execution. In the current industry downturn, the Company has failed to collect the annual minimum quantities of gas provided by the contractual take-or-pay clause, being forced to pre-pay the underlying gas volumes. Management believes that the weak industry outlook weighed down by declining demand and large gas availability on the marketplace, the possible evolution of sector-specific regulation and strong competitive pressures represent risk factors to the Company s ability to fulfill its minimum take obligations associated with its long-term supply contracts in the foreseeable future. For further discussion about our risks associated with take-or-pay contracts see "Item 3" and

"Item 5 Management s expectations of operations".

Sales of natural gas

In 2013, Eni s gas sales were 93.17 BCM, down by 2.3% from 2012. When excluding the effect of the divestment of Galp, gas sales were broadly in line with the previous year. Eni s sales in the domestic market increased by 1.08 BCM driven by higher spot sales and by higher sales to importers in Italy (up 1.94 BCM). This positive trend was more than offset by lower volumes marketed in the main European markets (down 5.61 BCM, particularly in Benelux, the Iberian Peninsula and the United Kingdom) due to declining gas demand and competitive pressure. Higher sales outside Europe (up 0.56 BCM) were driven by increasing LNG sales in the Far East, particularly in Japan and Korea. Exploration & Production sales in Northern Europe and in the United States (2.61 BCM) declined by 0.12 BCM due to lower sales in the United States.

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The tables below set forth Eni s sales of natural gas by principal market for the periods indicated.

Natural gas sales by entities	**2011**	**2012**	**2013**
		(BCM)	
Total sales of subsidiaries	**84.05**	**84.30**	**83.60**
Italy (including own consumption)	*34.60*	*34.66*	*35.76*
Rest of Europe	*44.84*	*44.57*	*42.30*
Outside Europe	*4.61*	*5.07*	*5.54*
Total sales of Eni s affiliates (Eni s share)	**9.85**	**8.29**	**6.96**
Italy	*0.08*	*0.12*	*0.10*
Rest of Europe	*8.14*	*6.45*	*5.05*
Outside Europe	*1.63*	*1.72*	*1.81*
Total sales of G&P	**93.90**	**92.59**	**90.56**
E&P in Europe and in the Gulf of Mexico [(a)]	2.86	2.73	2.61
Worldwide gas sales	**96.76**	**95.32**	**93.17**

(a) Exploration & Production sales include volumes marketed by the Exploration & Production Division in Europe (2.29, 2.06 and 2.08 BCM in 2011, 2012 and 2013, respectively) and in the Gulf of Mexico (0.57, 0.67 and 0.53 BCM in 2011, 2012 and 2013, respectively).

Natural gas sales by market	**2011**	**2012**	**2013**
		(BCM)	
ITALY	**34.68**	**34.78**	**35.86**
Wholesalers	5.16	4.65	4.58
Italian gas exchange and spot markets	5.24	7.52	10.68
Industries	7.21	6.93	6.07
Medium-sized enterprises and services	0.88	0.81	1.12
Power generation	4.31	2.55	2.11
Residential	5.67	5.89	5.37
Own consumption	6.21	6.43	5.93
INTERNATIONAL SALES	**62.08**	**60.54**	**57.31**
Rest of Europe	**52.98**	**51.02**	**47.35**
Importers in Italy	3.24	2.73	4.67
European markets	49.74	48.29	42.68
Iberian Peninsula	*7.48*	*6.29*	*4.90*
Germany-Austria	*6.47*	*7.78*	*8.31*
Benelux	*13.84*	*10.31*	*8.68*
Hungary	*2.24*	*2.02*	*1.84*
United Kingdom/Northern Europe	*4.21*	*4.75*	*3.51*
Turkey	*6.86*	*7.22*	*6.73*
France	*7.01*	*8.36*	*7.73*
Other	*1.63*	*1.56*	*0.98*
Extra European markets	**6.24**	**6.79**	**7.35**
E&P in Europe and in the Gulf of Mexico	**2.86**	**2.73**	**2.61**
WORLDWIDE GAS SALES	**96.76**	**95.32**	**93.17**

European markets

A review of Eni s presence in the key European markets is presented below.

Benelux. Eni holds a leadership position in the Benelux Countries (Belgium, the Netherlands and Luxembourg) granted by a direct presence, the integration with Distrigas operations, the presence in the retail and middle market and its significant exposure to spot markets in Western Europe. In 2013, sales in Benelux were mainly directed to industrial companies, power generation and wholesalers and amounted to 8.68 BCM (10.31 BCM in 2012), down by 1.63 BCM, or 15.8%, due to lower demand and rising competitive pressure. In 2012, Eni launched its brand in the business and retail gas and power market in Belgium. The Eni brand replaced that of local operators acquired in the past few years with the aim of consolidating its leadership in the market.

France. Eni sells natural gas to industrial clients, wholesalers and power generation as well as to the segments of retail and middle market. Eni is present in the French market through its direct commercial activities and through its subsidiary. Management plans to expand sales in France over the plan period growing volumes supplied to the business segments and increasing retail customers. In 2013, sales in France amounted to 7.73 BCM (8.36 BCM in 2012), a decrease of 0.63 BCM, or 7.5%, from a year ago. In 2013, Eni launched its brand in France, replacing those of the local operators acquired in the past few years with the aim of becoming one of the major retail operators in the Country.

Germany-Austria. Eni is present in the natural gas market through a direct marketing structure which sold in 2013 approximately 6.34 BCM in Germany and 0.25 BCM in Austria through its associate GVS (Gasversorgung Süddeutschland GmbH - Eni 50%) which sold approximately 5.24 BCM in 2013 (2.62 BCM being Eni s share). Management plans to drive growth in direct sales leveraging on the quality of its commercial offer, a projected expansion in its business customer base and the enhancement of direct presence on the market. In 2013, total sales in the Germany-Austria market amounted to 8.31 BCM, an increase of 0.53 BCM, or 6.8%, from a year ago.

Spain. Eni operates in the Spanish gas market through a direct marketing structure that markets its portfolio of LNG and through Unión Fenosa Gas (UFG) (Eni s interest 50%) which mainly supplies natural gas to industrial clients, wholesalers and power generation utilities. In addition, Eni sells gas transported via the Medgaz pipeline. In 2013, UFG gas sales in Europe amounted to 4.58 BCM (2.29 BCM Eni s share). UFG holds an 80% interest in the Damietta liquefaction plant, on the Egyptian coast (see below), and a 7.36% interest in a liquefaction plant in Oman. In addition, it holds interests in the Sagunto (Valencia) and El Ferrol (Galicia) re-gasification plants (42.5% and 18.9%, respectively). In 2013, Eni sales in Spain amounted to 4.9 BCM, decreasing from a year ago. Following the divestment of Galp, we no more sell gas in the Portuguese market (1.39 BCM in 2012).

Turkey. Eni sells gas supplied from Russia and transported via the Blue Stream pipeline. In 2013, sales amounted to 6.73 BCM, a decrease of 0.49 BCM, or 6.8% from a year ago.

United Kingdom. Eni through its subsidiary ETS markets in the United Kingdom the equity gas produced at Eni s fields in the North Sea and operates in the main continental natural gas hubs (NBP, Zeebrugge, TTF). In 2013, sales amounted to 3.51 BCM, an increase of 26.1% from a year ago.

Deborah Gas Storage Project in the Hewett Area, United Kingdom

The Deborah Gas Storage Project (DGSP) is a gas storage development to ensure gas supplies during the seasonal swings in demand. The project involves the Deborah reservoir (located in UKCS Block 48/30a) which will be connected to the National Transmission System at Bacton, via the Company s existing production terminal. Gas Storage License has been granted by the Department of Energy & Climate Change (DECC) while the North Norfolk District Council (NNDC) has approved the Deborah Project planning application subject to certain conditions. Appraisal works on the Deborah reservoir have also progressed, including the drilling and completion of an appraisal well and the related tests. Ongoing work with the relevant United Kingdom ministers and regulatory departments have continued in order to promote the continued role of natural gas within the United Kingdom energy mix and support the economic case for the DGSP with the aim of securing a stable revenue stream to the project thus enabling the entrance of new investors. At the end of 2012 the United Kingdom Department of Energy and Climate Change published its Gas Generation Strategy. It has then started an analysis of the costs and benefits of an intervention to support Gas Storage investments in the United Kingdom which could support the Eni project. However, government legislation is not expected to come into force until 2014, Eni therefore is targeting a possible FID in 2014-2015.

The LNG business

Eni operates in all phases of the LNG business: gas feeding, liquefaction, shipping, re-gasification and sale through operated activities or interests in joint ventures and associates. Eni s presence in the business is tied to the Company s plans to develop its large gas reserve base in Africa and elsewhere in the world. The LNG business has not been impacted by the economic downturn and oversupply affecting the European gas market, as well as by structural modifications in the U.S. market. LNG flexibility allowed to adapt the business model to the new scenario and to increase the value of the commodity entering in new markets.

Eni s main assets and projects in the LNG business are described below.

Qatar. Eni increased its development opportunities in the LNG business with access to new supply sources mainly from Qatar, under a 20-year agreement with RasGas (owned by Qatar Petroleum with a 70% interest and ExxonMobil with a 30% interest) and the Zeebrugge LNG terminal on the Western coast of Belgium.

Egypt. Eni, through its interest in Unión Fenosa Gas, owns a 40% interest in the Damietta liquefaction plant with a capacity of approximately 5 mmtonnes/y of LNG which equates to a feedstock of 7.56 BCM/y in natural gas out of which the Gas & Power segment interest is up to 2.2 BCM/y to be marketed in Europe.

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Spain. Eni through Unión Fenosa Gas holds a 21.25% interest in the Sagunto re-gasification plant, near Valencia, with a capacity of 8.8 BCM/y and a LNG storage capacity of 450,000 CM which will be increased to 600,000 CM after the ongoing construction of a fourth tank. At present, Eni s re-gasification capacity entitlement amounts to 1.9 BCM/y of gas. Eni through Unión Fenosa Gas also holds a 9.45% interest in the El Ferrol re-gasification plant, located in Galicia, with a treatment capacity of approximately 3.6 BCM/y, of which 0.34 BCM/y being Eni s capacity entitlements. The LNG storage capacity of the plant is 300,000 CM in two tanks.

United States

Cameron. The Cameron LNG terminal is located on the coastline of Louisiana. The facility where Eni owns a capacity entitlement to treat LNG was completed in 2009. Considering current oversupply conditions in the U.S. gas market, the partners of the project are planning for converting the Cameron facility into a liquefaction plant to export LNG. The relevant U.S. Authorities have so far granted the authorization to export while they are still evaluating the reconversion project. Eni has accrued in 2013 the expected costs of the unused re-gasification plant.

Pascagoula. This project is part of an upstream development project related to the construction of an LNG plant in Angola designed to produce 5.2 mmtonnes of LNG (approximately 7.3 BCM/y) destined to the North American market in order to monetize part of the Company s gas reserves. As part of the downstream leg of the project, Eni signed a 20-year contract with Gulf LNG to buy 5.8 BCM/y of the re-gasification capacity of the plant under construction near Pascagoula in Mississippi. The re-gasification facility is in operation from the last quarter of 2012. Eni USA Gas Marketing Llc also signed a 20-year contract to purchase approximately 0.9 BCM/y of re-gasified gas downstream the terminal owned by Angola Supply Services, a company whose partners also own Angola LNG. In 2012, the partners and local authorities reached an agreement for the sale of LNG on Asian and European markets due to the changed gas demand outlook in the U.S. market.

LNG sales	**2011**	**2012**	**2013**
		(BCM)	
G&P sales	**11.8**	**10.5**	**8.4**
Rest of Europe	9.8	7.6	4.6
Extra European markets	2.0	2.9	3.8
E&P sales	**3.9**	**4.1**	**4.0**
Liquefaction plants:			
- Soyo (Angola)			0.1
- Bontang (Indonesia)	0.6	0.6	0.5
- Point Fortin (Trinidad & Tobago)	0.4	0.5	0.6
- Bonny (Nigeria)	2.5	2.7	2.4
- Darwin (Australia)	0.4	0.3	0.4
	15.7	**14.6**	**12.4**

Electricity sales and power generation

Electricity sales

As part of its marketing activities in Italy, Eni engages in selling electricity on the Italian market principally on the open market, at industrial sites and on the Italian exchange for electricity. Supplies of electricity include both own production volumes through gas-fired, combined-cycle facilities and purchases on the open market. This activity has been developed in order to capture further value along the gas value-chain leveraging on the Company s large gas availability. In addition, with the aim of developing and retaining valuable customers in the residential space and middle to large industrial users, the Company has been developing a commercial offer that provides the combined supply of gas, power and fuels. In 2013, power sales (35.05 TWh) were directed to the free market (82%), the Italian power exchange (6%), industrial sites (9%) and others (3%). Compared with 2012, electricity sales were down by 17.7%, due to lower volumes traded on the Italian power exchange and declining sales to wholesales, partly offset by higher sales to retail customers.

Power availability	2011	2012	2013
		(TWh)	
Power generation sold	25.23	25.67	23.03
Trading of electricity [a]	15.05	16.91	12.02
	40.28	**42.58**	**35.05**
Power sales by market			
Free market [a]	27.25	31.84	28.73
Italian exchange for electricity	8.67	6.10	1.96
Industrial plants	3.23	3.30	3.31
Other [a]	1.13	1.34	1.05
	40.28	**42.58**	**35.05**

(a) Include positive and negative imbalances.

Power generation

Eni s main power generation plants are located in Ferrera Erbognone, Ravenna, Livorno, Taranto, Mantova, Brindisi, Ferrara and in various photovoltaic parks. In 2013, power production was 23.03 TWh, down 2.64 TWh, or 10.3% from 2012. As of December 31, 2013, installed operational capacity was 5.3 GW (5.3 GW as of December 31, 2012). Electricity trading declined (down 4.89 TWh, or 28.9%) due to lower purchases related performer on the market.

By 2015, Eni expects to complete its plans for capacity expansion targeting an installed capacity of 5.4 GW. In the medium term, Eni intends to consolidate operations at its power generation plants and to enhance the flexibility of assets in order to better meet market needs. Furthermore Eni intends to develop the production from renewable sources focusing on photovoltaic power plants, and on the Company s "Green Chemistry" project for the remediation of the Porto Torres site, where it will be also build a bio-mass power plant. Development activities are currently underway at the Bolgiano (Eni 100%) plant. Supplies of natural gas are expected to amount to approximately 6 BCM/y from Eni s diversified supply portfolio. New installed generation capacity uses the combined-cycle gas-fired technology (CCGT) and produces electricity combined with heat (cogeneration) used to feed industrial processes and district heating networks, ensuring a high level of efficiency and low environmental impact. In particular, management estimates that for a given amount of energy (electricity and heat) produced, using the CCGT technology instead of conventional power generation technology, the emission of carbon dioxide reduces by approximately 5 mmtonnes, on an energy production of 26.5 TWh. The electricity produced in cogeneration does not require the purchase of green certificates. According the regulations currently in force, are required to supply certain percentages of energy derived from renewable sources calculated as a function of the energy produced from fossil-fuel or, alternatively, to purchase green certificates (which grant exemptions to the obligation to supply in proportionate amounts energy derived from fossil-fuel and renewable sources). The Legislative Decree No. 28/2011 provides for a gradual reduction down to zero, in 2015, of the share of fossil-fuel derived electricity that producers are entitled to offset by the purchase of green certificates. Eni and other cogeneration producers are currently involved in a legal proceeding against the Italian state-owned company promoting and supporting renewable energy resources (GSE - Gestore Servizi Elettrici), which is in charge of controlling the compliance of obligation, in relation to way of assessing energy produced in cogeneration. In particular, the GSE alleges that that producers are not allowed to assess the amount of electricity produced from cogeneration as energy derived from renewable sources, according to the

AEEG s Decision No. 42/02; therefore GSE maintains that producers have to buy a greater amount of green certificates to maintain their production levels. However, with a further administrative decision, the electricity produced from cogeneration has been considered eligible to be awarded with "white certificates", in proportion to primary energy saving granted to the system. Power plants built before 2007 will be entitled to gain white certificates in a measure equivalent to 30% of the amount awarded to a new project. In spite of these incentives, we believe that in the next four years our expenses to comply with environmental regulation will increase as a result of stricter rules that will apply to the award of emission allowances in the EU emission trading mechanism, causing the Company to increase its purchases of allowance on the free market.

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The main assets of Eni power generation activities in Italy are provided in the table below.

Site	Total installed capacity in 2013 (a) (MW)	Technology	Fuel
Brindisi	1,321	CCGT	gas
Ferrera Erbognone	1,030	CCGT	gas/syngas
Livorno	199	Power station	gas/fuel oil
Mantova	836	CCGT	gas
Ravenna	972	CCGT	gas
Taranto	75	Power station	gas/fuel oil
Ferrara	841	CCGT	gas
Bolgiano	30	Power station	gas
Photovoltaic parks	4	Power station	photovoltaic energy
	5,308		

(a) Capacity available after completion of dismantling of obsolete plants.

Power Generation		**2011**	**2012**	**2013**
Purchases				
Natural gas	(mmCM)	5,008	5,206	4,635
Other fuels	(ktoe)	528	462	449
- of which steam cracking		*99*	*98*	
Production				
Electricity	(TWh)	25.23	25.67	23.03
Steam	(ktonnes)	14,401	12,603	10,099
Installed generation capacity	(GW)	**5.3**	**5.3**	**5.3**

International transport

Eni has transport rights on a large European network of integrated infrastructures for transporting natural gas, which links key consumption markets with the main producing areas (Russia, Algeria, Libya and the North Sea). Eni pays annual fixed amounts to lease the transport capacity from pipeline owners under ship-or-pay contracts which are similar to take-or-pay contracts.

Eni also retains ownership interests in certain pipeline companies which run and operate the facility by leasing the relevant capacity to both shareholders and third-party shippers. The main assets of Eni transport activities are provided in the table below.

International transport infrastructure

Route	Lines	Total length	Diameter	Transport capacity (1)	Transit capacity (2)	Compression stations

	(units)	**(km)**	**(inch)**	**(BCM/y)**	**(BCM/y)**	**(No.)**
TTPC (Oued Saf Saf-Cap Bon)	2 lines of km 370	740	48	34.0	33.2	5
TMPC (Cap Bon-Mazara del Vallo)	5 lines of km 155	775	20/26	33.5	33.5	
GreenStream (Mellitah-Gela)	1 line of km 520	520	32	8.0	8.0	1
Blue Stream (Beregovaya-Samsun)	2 lines of km 387	774	24	16.0	16.0	1

(1) Includes both transit capacity and volumes of natural gas destined to local markets and withdrawn at various points along the pipeline.
(2) The maximum volume of natural gas which is input at various entry points along the pipeline and transported to the next pipeline.

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International transport activities

The TTPC pipeline, 740-kilometer long, is made up of two lines that are each 370-kilometer long with a transport capacity of 34.0 BCM/y and five compression stations. This pipeline transports natural gas from Algeria across Tunisia from Oued Saf Saf at the Algerian border to Cap Bon on the Mediterranean coast where it links with the TMPC pipeline.

The TMPC pipeline for the import of Algerian gas is 775-kilometer long and consists of five lines that are each 155-kilometer long with a transport capacity of 33.5 BCM/y. It crosses the underwater Sicily Channel from Cap Bon to Mazara del Vallo in Sicily, the point of entry into the Italian natural gas transport system.

The GreenStream pipeline, jointly-owned with the Libyan National Oil Co, started operations in October 2004 for the import of Libyan gas produced at Eni operated fields Bahr Essalam and Wafa. It is 520-kilometer long with a transport capacity of 8 BCM/y and crosses underwater in the Mediterranean Sea from Mellitah on the Libyan coast to Gela in Sicily, the point of entry into the Italian natural gas transport system.

Eni holds a 50% interest in the Blue Stream underwater pipeline (water depth greater than 2,150 meters) linking the Russian coast to the Turkish coast of the Black Sea. This pipeline is 774-kilometer long on two lines and has transport capacity of 16 BCM/y. It is part of a joint venture to sell gas produced in Russia on the Turkish market.

The South Stream project

Eni and Gazprom are jointly assessing the technical and economic feasibility of a project to build a new import route to Europe to market gas produced in Russia (the so-called South Stream project). The South Stream pipeline will provide transport capacity of 63 BCM/y and is expected to be composed by two sections: (i) an offshore section crossing the Black Sea from the Russian coast at Anapa (in the same Southern Russian area of Beregovaya, the starting point of the Blue Stream pipeline) to the Bulgarian coast at Varna; and (ii) an onshore section crossing Bulgaria for which two options are currently being evaluated: one pointing North-West and another one pointing South-West. Eni is involved only in the offshore section of the project. In September 2011, Eni and Gazprom in the context of their strategic partnership signed a series of agreements in areas of common interest including the development of the offshore section of the South Stream project through the definition of terms for the participation to the project of gas operators Wintershall and EDF, each with a 15% stake; Gazprom and Eni hold 50% and 20% interests, respectively. On November 14, 2012, in accordance with the shareholders agreement the partners confirmed that South Stream project will proceed according to the agreed schedule aiming at transporting the first gas through the Black Sea by the end of 2015. Pursuant to the shareholder agreement, the minority shareholders including Eni have the right to divest from the project in case certain future conditions are not satisfied. In 2014, the procurement process was started up. The construction of the first line, the shore crossings and associated facilities for all the pipelines has been assigned to Saipem.

Capital expenditures

See "Item 5 Liquidity and capital resources Capital expenditures by segment".

Refining & Marketing

Eni s Refining & Marketing segment engages in the supply of crude oil, refining and marketing of refined products, trading and shipping of crude oil and refined products primarily in Italy and in Central-Eastern Europe. In Italy, Eni is the largest refining and marketing operator in terms of capacity and market share. The Company s operations are fully integrated through refining, supply, trading, logistics and marketing so as to maximize cost efficiencies and effectiveness of operations.

The outlook in the Refining & Marketing segment remains depressed as management does not expect any significant improvement in the trading environment over the next four years of the industrial plan and as excess capacity, weak demand and continuing competitive pressure from product streams coming from Russia, Asia and ultimately the U.S. continue to hurt our profitability. The ongoing economic downturn is anticipated to weigh on the recovery of demand for fuels, while high costs of the crude oil feedstock and energy utilities will continue squeezing refining margins. On the supply side, it is unlikely that ongoing capacity rationalization will help absorb product surpluses on the short term. Finally we expect that our refining margins at complex cycles will continue to suffer from ongoing narrowing differential between the benchmark Brent and the heavy qualities of crude oil supplied by our operations due to reduced supplies of heavy crudes in the Mediterranean Area from Russia and other countries. Also retail and wholesale marketing activities of refined products will be affected by sluggish demand and product oversupply that is expected to trigger pricing competition. See "Item 3 Risk factors" and "Regulation" below.

Due to the challenging market environment and industry downturn, we plan to implement all available levers to improve operations efficiency and profitability. The main planned initiatives in our refining operations are:

- to reduce refining capacity by closing marginal lines of operations and through the full conversion of the Venice refinery into a facility which will be able to process bio-fuels;
- to pursue better integration of refineries and logistic assets and seek synergies with the Exploration & Production segment to monetize equity crudes and proprietary technologies;
- to maximize refinery flexibility and conversion to extract value from heavy crudes;
- to achieve energy efficiency initiatives;
- to rationalize logistic costs and implement other cost-saving measures involving maintenance, labor and other fixed plant expenses;
- to strictly select capital expenditures; and
- to boost margins leveraging on risk management activities.

In the marketing activity, we plan to preserve our profitability by:

- preserving our marketing margins at our Italian outlets by rationalizing and divesting marginal service stations and continuously upgrading our best plants and developing new revenues streams from non oil activities and other services to the driver;
- preserving our customer base by effective marketing actions, fidelity cards, cross initiatives with other operators (food distributors, telecoms etc.), rolling out our "eni" brand and service excellence;
- boosting margins by increasing the number of fully-automated outlets; and
- selectively growing our market share in European markets and divesting from marginal areas.

In the 2014-2017 period, we plan to make capital expenditures amounting to euro 2.5 billion carefully selecting capital projects. Management plans to make expenditures to convert the Venice plant into a bio-refinery, continuous refinery upgrade as well as to improve plant efficiency and reliability. Retail activities will attract some 25% of the planned expenditure which will be mainly directed to upgrade and modernize our service stations in Italy and in selected European countries, and to complete the network rebranding.

Based on the planned initiatives, management expects Eni s refining and marketing operations to break-even in the next four-year period assuming a constant trading environment.

The matters regarding future plans discussed in this section and elsewhere herein are forward-looking statements that involve risks and uncertainties that could cause the actual results to differ materially from those in such forward looking statements. Such risks and uncertainties include difficulties in obtaining approvals from relevant Antitrust Authorities and developments in the relevant market.

Supply

In 2013, a total of 65.96 mmtonnes of crude were purchased by the Refining & Marketing segment (62.21 mmtonnes in 2012), of which 26.15 mmtonnes from Eni s Exploration & Production segment, 25.27 mmtonnes on the spot market and 14.54 mmtonnes were purchased under long-term supply contracts with producing countries. Approximately 26% of crude purchased in 2013 came from Russia, 19% from West Africa, 14% from the North Sea, 12% from North Africa, 6% from the Middle East, 6% from Italy and 17% from other areas. In 2013, some 43.96

mmtonnes of crude purchased were marketed (up 7.40 mmtonnes from 2012, or 20.2%). In addition, 5.31 mmtonnes of intermediate products were purchased (4.53 mmtonnes in 2012) to be used as feedstock in conversion plants and 17.79 mmtonnes of refined products (20.52 mmtonnes in 2012) were purchased to be sold on markets outside Italy (13.73 mmtonnes) and on the domestic market (4.06 mmtonnes) as a complement to available production.

Refining

In 2013, Eni s refining system had total refinery capacity (balanced with conversion capacity) of approximately 39.3 mmtonnes (equal to 787 KBBL/d) and a conversion index of 62%. Conversion index is a measure of refinery complexity. The higher the index, the wider the spectrum of crude qualities and feedstock that a refinery is able to process thus enabling it to benefit from the cost economies which the Company generally expects to achieve as certain qualities of crude (particularly the heavy ones) may trade at discount with reference to the light crude Brent benchmark. Eni s five 100% owned refineries have balanced capacity of 28.7 mmtonnes (equal to 574 KBBL/d), with a 68% conversion index. In 2013, Eni s refineries throughputs in Italy and outside Italy was 27.38 mmtonnes.

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The table below sets forth certain statistics regarding Eni s refineries as of December 31, 2013.

Refining system in 2013

	Ownership share (%)	Distillation capacity (total) (KBBL/d)	Distillation capacity (Eni s share) (KBBL/d)	Primary balanced refining capacity (1)(Eni s share) (KBBL/d)	Conversion index (2) (%)	Fluid catalytic cracking - FCC (3) (KBBL/d)	Residue conversion (KBBL/d)	Go-Finer/ Mild Hydro-cracking/ (KBBL/d)	Mild Hydro-cracking/ Hydro-cracking (KBBL/d)	Visbreaking/ thermal cracking (KBBL/d)	Coking (KBBL/d)	Distillation capacity utilization rate (Eni s share) (%)	Balanced refining capacity utilization rate (Eni s share) (%)
Wholly-owned refineries		**685**	**685**	**574**	**68**	**69**	**35**	**37**	**66**	**89**	**46**	**61**	**66**
Italy													
Sannazzaro	100	223	223	190	73	34	13		51	29		74	87
Gela	100	129	129	100	142	35		37			46	22	29
Taranto	100	120	120	120	72		22			38		65	65
Livorno	100	106	106	84	11							73	92
Porto Marghera	100	107	107	80	20					22		44	37
Partially-owned refineries (4)		**874**	**245**	**213**	**47**	**167**	**25**		**99**	**27**		**79**	**84**
Italy													
Milazzo	50	248	124	100	60	45	25		32			77	83
Germany													
Vohburg/Neustadt (Bayernoil)	20	215	43	41	36	49			43			92	92
Schwedt	8.33	231	19	19	42	49				27		95	94
Czech Republic													
Kralupy and Litvinov	32.4	180	59	53	30	24			24			78	78
Total refineries		**1,559**	**930**	**787**	**62**	**236**	**60**	**37**	**165**	**116**	**46**	**72**	**71**

(1) Actual production capacity: Venice conversion in "Green Refinery", Gela with only a production line working.
(2) Stated in fluid catalytic cracking equivalent/topping (% by weight), based on 100% of balanced primary distillation capacity.
(3) Conversion plant where vacuum feedstock undergoes cracking at high pressure and moderate temperature thus producing mostly high quality gasoline. This kind of plant guarantees high operating flexibility to the refinery.
(4) Capacity of conversion plant is 100%.

Italy

Eni s refining system in Italy is composed of five wholly-owned refineries and a 50% share in the Milazzo refinery in Sicily. Eni s refineries in Italy operate and plan in order to maximize asset value according to the markets and the integration with Eni s other activities.

Sannazzaro refinery has balanced refining capacity of 190 KBBL/d and a conversion index of 72.8%. Management believes that this site is one of the most efficient refineries in Europe. Located in the Po Valley, it mainly supplies markets in North-Western Italy and Switzerland. The high flexibility and conversion capacity of this refinery allows it to process a wide range of feedstock. From a logistical standpoint this refinery is located along the route of the Central Europe pipeline, which links the Genoa terminal with French speaking Switzerland. This refinery contains two primary distillation plants and relevant facilities, including three desulphurization units. Conversion is obtained through a fluid catalytic cracker (FCC), two hydrocrackers (HdC), the last unit entered into operations in June 2009, which enable middle distillate conversion and a visbreaking thermal conversion unit with a gasification facility loaded with heavy residue from visbreaking unit (tar) to produce syn-gas to feed the nearby EniPower power plant at Ferrera Erbognone. In 2013, the Eni Slurry Technology (EST) project was started up. The conversion plant with a 23 KBBL/d capacity is aimed to process extra heavy crude with high sulphur content increasing middle distillates and reducing fuel oil. Therefore, Eni is developing conversion technology of Slurry Dual Catalyst (an evolution of EST), based on a combination of two nano-catalysts, could lead to a relevant breakthrough in the EST process, increasing its productivity and improving product quality, reducing expenditure and operating costs.

A further project is the proprietary process for hydrogen production, Hydrogen SCT-CPO (Short Contact Time-Catalytic Partial Oxidation) and the design is nearly over. This reforming technology transforms gaseous and liquid hydrocarbons (also derived from bio-mass) into synthetic gas (carbon monoxide and hydrogen) at competitive costs.

Taranto refinery has balanced refining capacity of 120 KBBL/d and a conversion index of 72%. This refinery process most of oil produced in Eni s Val d Agri fields carried to Taranto through the Monte Alpi pipeline (in 2013 a total of 2.87 mmtonnes of this oil were processed). It principally produces fuels for automotive use and residential heating purposes for the Southern Italian markets.

The complexity is achieved through a Residue Hydroconversion Unit (RHU) - Hydrocracking process and a "Two Stage" Visbreaking-Thermal Cracking unit.

Gela refinery has balanced refining capacity of 100 KBBL/d and a conversion index of 142%. Located on the Southern coast of Sicily, it is integrated with upstream operations processing heavy crude produced from Eni s nearby offshore and onshore fields. Its high conversion level is ensured by an FCC unit with go-finer for feedstock upgrading and two coking plants enabling conversion of heavy residues topping or vacuum residues. In order to achieve full compliance with the tightest environmental standards, in the power station there is SNOx plant to remove sulphur dioxide, nitrogen oxides and particulates from flue gases. An underway refurbishment of the Gela power plant, substantially renewing pet-coke boilers, will increase profitability maximizing synergies from refining and power generation.

In 2013, started the restructuring plan to recover the economic viability of the refinery, maximizing the production of diesel providing the closure of gasoline (FFC and ancillary) and polyethylene production cycles and the conversion of gofiner in Hydrocracking.

Livorno refinery, with balanced refining capacity of 84 KBBL/d and a conversion index of 11%, manufactures mainly gasoline, fuel oil for bunkering and lubricant bases. Besides its primary distillation plants, this refinery contains two lubricant manufacturing lines. Its infrastructures including highways, railways and pipeline connecting the site with the local harbor and with the Florence storage sites through two pipelines optimizing intake, handling and distribution of products.

Porto Marghera refinery, with balanced refining capacity of 80 KBBL/d and a conversion index of 20%, supplies mainly markets in North-Eastern Italy and Austria. Besides its primary distillation plants, this refinery contains a two stage thermal conversion plant (visbreaking/thermal cracking) to increase yields of valuable products.

Eni will turn the refinery into a "bio-refinery" based on proprietary technology for the production of bio-diesel based on its Ecofining technology. The conversion to a Green Refinery has started in September 2013 and bio-fuel production start-up is expected in 2014. The plant will be associated with a logistics center.

Milazzo refinery, participated on equal share by Eni and Kuwait Petroleum Italy, with balanced refining capacity of 100 KBBL/d and conversion index of 60%, is located on the Northern coast of Sicily. Besides two primary distillation plants, refinery has a fluid catalytic cracker unit (FCC), a hydrocracker (HdC), and one unit of residue treatment (LC-Finer).

Outside Italy

In Germany, Eni s share in the Schwedt refinery is 8.3% and 20% in Bayernoil, an integrated industrial hub that includes Vohburg and Neustadt refineries. Eni s refining capacity in Germany is approximately 60 KBBL/d mainly to supply Eni s distribution network in Bavaria and Eastern Germany. In Czech Republic, Eni s share in Ceská Rafinérská is 32.4%, that includes two refineries, Kralupy and Litvinov. Eni s refining capacity amounts to about 53 KBBL/d to supply Eastern Europe.

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Table below sets forth Eni s products availability figures for the periods indicated.

Availability of refined products	**2011**	**2012**	**2013**
		(mmtonnes)	
ITALY			
Refinery throughputs			
At wholly-owned refineries	22.75	20.84	18.99
Less input on account of third parties	(0.49)	(0.47)	(0.57)
At affiliated refineries	4.74	4.52	4.14
Refinery throughputs on own account	**27.00**	**24.89**	**22.56**
Consumption and losses	(1.55)	(1.34)	(1.23)
Products available for sale	**25.45**	**23.55**	**21.33**
Purchases of refined products and change in inventories	3.22	3.35	4.42
Products transferred to operations outside Italy	(1.77)	(2.36)	(1.85)
Consumption for power generation	(0.89)	(0.75)	(0.55)
Sales of products	**26.01**	**23.79**	**23.35**
OUTSIDE ITALY			
Refinery throughputs on own account	**4.96**	**5.12**	**4.82**
Consumption and losses	(0.23)	(0.23)	(0.22)
Products available for sale	**4.73**	**4.89**	**4.60**
Purchases of finished products and change in inventories	12.51	17.29	13.69
Products transferred from Italian operations	1.77	2.36	1.85
Sales of products	**19.01**	**24.54**	**20.14**
Refinery throughputs on own account	**31.96**	**30.01**	**27.38**
of which: refinery throughputs of equity crude on own account	*6.54*	*6.39*	*5.93*
Total sales of refined products	**45.02**	**48.33**	**43.49**
Crude oil sales	**32.10**	**36.56**	**43.96**
TOTAL SALES	**77.12**	**84.89**	**87.45**

In 2013, refinery throughputs were 27.38 mmtonnes, decreasing by 2.63 mmtonnes, or 8.8% versus 2012. Processed volumes in Italy decreased by 9.4% compared to 2012, due to the planned shutdown of the Venice refinery following the Green Refinery project and in all the remaining plants due to a downsizing of productive assets in relation to declining refining margins. Outside Italy, Eni s refining throughputs decreased by 5.9% (down approximately 302 ktonnes) mainly reflecting the shutdown at the Kralupy refinery in the Czech Republic for maintenance and lower throughputs in order to mitigate the negative impact of lower refining margins.

Wholly-owned refineries throughputs were 18.99 mmtonnes, down by 1.85 mmtonnes (or 8.9%) from 2012 determining a refinery utilization rate of 66%, declining by six percentage points from 2012, reflecting the unfavorable scenario. Approximately 23.7% of processed crude was supplied by Eni s Exploration & Production segment, representing a 0.9 percentage points increase from 2012 (22.8%).

Eni s Exploration & Production segment supplied approximately 23.7% of crudes, up 0.9% versus 2012.

Logistics

Eni is a primary operator in storage and transport of petroleum products in Italy with its logistical integrated infrastructure consisting of 18 directly managed storage sites and a network of petroleum product pipelines for products sale and storage of LPG and crude. Located in the Vado Ligure-Genova (Petrolig), Arquata Scrivia (Sigemi), Venice (Petroven), Ravenna (Petra) and Trieste (DCT) sites, they reduce logistic costs, and increase efficiency.

Eni s logistic model is based on a hub structure covering five main areas. These hubs monitor and centralize products flows in order to lower collection and delivery costs. Eni holds five partnerships with major Italian operators.

Eni operates in oil and refined products transport: (i) by sea through spot and long-term contracts of tanker ships; and (ii) through an owned pipeline network extending approximately 1,462-kilometer long.

Secondary distribution to retail and wholesale markets is carried out through outsourcing to little tanker owners and represent leading market positions in their own geographical area.

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Marketing

Eni markets a wide range of refined petroleum products, primarily in Italy, through an extensive operated network of service stations, franchises and other distribution systems.

The table below sets forth Eni s sales of refined products by distribution channel for the periods indicated.

Oil products sales in Italy and outside Italy	2011	2012	2013
		(mmtonnes)	
Italy			
Retail	8.36	7.83	6.64
Wholesale	9.36	8.62	8.37
	17.72	**16.45**	**15.01**
Petrochemicals	1.71	1.26	1.32
Other sales	6.58	6.08	7.01
Total	**26.01**	**23.79**	**23.34**
Outside Italy			
Retail	3.01	3.04	3.05
Wholesale	4.27	4.38	4.66
	7.28	**7.42**	**7.71**
Other sales	11.73	17.12	12.44
Total	**19.01**	**24.54**	**20.15**
TOTAL SALES	**45.02**	**48.33**	**43.49**

In 2013, sales volumes of refined products (43.49 mmtonnes) decreased by 4.84 mmtonnes from 2012, down 10%, due mainly to lower volumes sold to oil companies and traders outside Italy.

Retail sales in Italy

In 2013, retail sales in Italy of 6.64 mmtonnes decreased by approximately 1.19 mmtonnes, down 15.2%, from 2012 driven by lower consumption of gasoil and gasoline, in particular in highway service stations related to the decline in freight transportation. Average gasoline and gasoil throughput (1,657 kliters) decreased by approximately 318 kliters from 2012. Eni s retail market share for 2013 was 27.5%, down 3.7 percentage points from 2012.

At December 31, 2013, Eni s retail network in Italy consisted of 4,762 service stations, 18 less than at December 31, 2012 (4,780 service stations), resulting from the negative balance of the closing of service stations with low throughput (51 units), the release of one motorway concession, partially offset by the positive contribution of acquisitions/releases of lease concessions (34 units).

In 2013, even sales of premium fuels (fuels of the "Eni Blu+" line with high performance and lower environmental impact) were affected by the decline in domestic consumption and high price levels and were lower than the previous year. In particular, sales of Eni BluDiesel+ amounted to approximately 231 mmtonnes (approximately 278 mmliters) with a decline of approximately 61 ktonnes from 2012 and represented 5.3% of volumes of gasoil marketed by Eni s retail network. At December 31, 2013, service stations marketing BluDiesel+ totaled 3,909 units (4,123 at year-end 2012) covering approximately 82% of Eni s network. Retail sales of BluSuper+ amounted to 30 ktonnes (approximately 41 mmliters), decreasing by 4 ktonnes from 2012, and covered 1.6% of gasoline sales on Eni s retail network (broadly in line with previous year). As of December 31, 2013, service stations marketing BluSuper+ totaled 2,171 units (2,505 at December 31, 2012), covering approximately 46% of Eni s network.

In 2013, Eni continued the development of innovative and bio-fuels with proprietary additives and detergents that provide better gasoline and gasoil with a "keep clean" component.

Retail sales in the rest of Europe

Eni s strategy in the rest of Europe is focused on selectively growing its market share, particularly in Germany and Austria leveraging on the synergies ensured by the proximity of these markets to Eni s production and logistic facilities and to divest from the marginal area with weak growth prospects.

In 2013, retail sales of refined products marketed in the rest of Europe (3.05 mmtonnes) were basically stable (up 0.3%). Volume additions in Germany and Austria were almost completely offset by lower sales in the Czech Republic and Hungary.

At December 31, 2013, Eni s retail network in the Rest of Europe consisted of 1,624 service stations, an increase of 20 units from December 31, 2012 (1,604 service stations). The network evolution was as follows: (i) the closing of 25 low throughput service stations mainly in France; (ii) the positive balance of acquisitions/releases of lease concessions (26 units) in particular in Germany and Austria; (iii) the purchase of 18 service stations, in particular in France and Germany; and (iv) the opening of one new outlet. Average throughput (2,322 kliters) was in line with 2012 (2,319 kliters).

The key markets of Eni s presence are: Austria with a 11.9% market share, Hungary with 11.7%, Czech Republic with 9.8%, Slovakia with 9.7%, Switzerland with 7.3% and Germany with a 3.2% on national base. These market shares were calculated by Eni based on public data on national consumption and Eni s sales volumes. Non-oil activities in the rest of Europe are present in 1,085 service stations (Eni owned network), of which 326 are in Germany, 209 in Austria and 130 in France, with a virtually complete of owned stations.

Other businesses

Wholesale

Eni markets gasoline and other fuels on the wholesale market in Italy, including diesel fuel for automotive use and for heating purposes, for agricultural vehicles and for vessels and fuel oil. Major customers are resellers, agricultural users, manufacturing industries, public utilities and transports, as well as final users (transporters, condominiums, farmers, fishers, etc.). Eni provides its customers with its expertise in the area of fuels with a wide range of products that cover all market requirements. Along with traditional products provided with the high quality Eni standard, there is also an innovative low environmental impact line, which includes AdvanceDiesel especially targeted for heavy duty public and private transports. Customer care and product distribution is supported by a widespread commercial and logistical organization presence all over Italy articulated in local marketing offices and a network of agents and concessionaires.

In 2013, sales volumes on wholesale markets in Italy (8.37 mmtonnes) declined by approximately 253 ktonnes, down 2.9%, mainly due to lower sales of bunkering and bitumen reflecting a decline in demand, mostly completely offset by higher volumes sold of fuel oil and minor products. Average market share in 2013 was 28.8% (29.5% in 2012). Supplies of feedstock to the petrochemical industry (1.32 mmtonnes) slightly increased from 2012 (up 62 ktonnes) due to higher feedstock supplies. Wholesale sales in the Rest of Europe of approximately 4.23 mmtonnes increased by 6.8% from 2012 due to higher sales in Slovenia and France. Sales declined in Austria. Other sales (19.45 mmtonnes) decreased by 3.75 mmtonnes, or 16.2%, mainly due to lower sales to other oil companies.

Eni also markets jet fuel directly or through local partners at 45 airports, of which 26 are in Italy. In 2013, these sales amounted to 2.0 mmtonnes (of which 1.6 mmtonnes are in Italy). Eni is also active in the international market of bunkering, marketing marine fuel mainly in 106 ports, of which 72 are in Italy. In 2013, marine fuel sales were 1.33 mmtonnes (1.23 mmtonnes in Italy).

LPG

In Italy, Eni is leader in LPG production, marketing and sale with 619 ktonnes sold for heating and automotive use equal to a 20.8% market share. An additional 257 ktonnes of LPG were marketed through other channels mainly to oil companies and traders. LPG activities in Italy are supported by direct production, availability from 5 bottling plants and 3 owned storage sites, in addition to products imported at coastal storage sites located in Livorno, Naples and Ravenna.

Outside Italy, LPG sales in 2013 amounted to 510 ktonnes of which 398 ktonnes in Ecuador where LPG market share is around 37.8%.

Lubricants

Eni operates six (owned and co-owned) blending plants, in Italy, Europe, North and South America and the Far East. With a wide range of products composed of over 650 different blends Eni masters international state of art know-how for the formulation of products for vehicles (engine oil, special fluids and transmission oils) and industries (lubricants for hydraulic systems, industrial machinery and metal processing). In Italy, Eni is leader in the manufacture and sale of lubricant bases. Base oils are manufactured primarily at Eni s refinery in Livorno. Eni also owns one facility for the production of additives and solvents in Robassomero. In 2013, retail and wholesale sales in Italy amounted to 94 ktonnes with a 23.6% market share. Eni also sold approximately 3 ktonnes of special products (white oils, transformer oil and anti-freeze fluids). Outside Italy sales amounted to approximately 170 ktonnes, of these about 40% were registered in Europe.

Oxygenates

Eni, through its subsidiary Ecofuel (100% Eni s share), sells approximately 1 mmtonnes/y of oxygenates, mainly ethers (approximately 2.7% of world demand) and methanol (approximately 0.6% of world demand). About 72% of oxygenates are produced in Eni s plants in Italy (Ravenna), in Venezuela (in joint venture with Pequiven) and Saudi Arabia (in joint venture with Sabic) and the remaining 28% is bought and resold. Eni distributes bio-ETBE in the Italian market in compliance with the new legislation indicating minimum content of bio-fuels. Bio-ETBE like MTBE is an octane booster gained a relevant position in the formulation of gasoline in European Union, because it is produced from ethanol from agricultural crops and qualified as bio-component in European directive on bio-fuels.

From January 1, 2012, the compulsory content of bio-fuels increases to 4.5% (4% in 2011) and through Bio-ETBE and bio-diesel (of 1st and 2nd generation) blending into fossil fuels Eni covered the compliance within 109.6% in 2012.

Eni plans to cover compliance through Bio-ETBE, FAME, green diesel from Porto Marghera site, and direct blending of ethanol in gasoline in particular in some extents of Sannazzaro refinery inland.

Capital expenditures

See "Item 5 Liquidity and capital resources Capital expenditures by segment".

Engineering & Construction

Eni engages in engineering, construction and drilling both offshore and onshore for the oil&gas industry through Saipem, a subsidiary listed on the Italian Stock Exchange (Eni s interest is 42.91%), and Saipem s controlled entities. Saipem boasts a strong competitive position in the market for services to the oil industry, particularly in executing large, complex EPC contracts for the construction of offshore and onshore facilities and systems to develop hydrocarbons reserves as well as LNG, refining and petrochemical plants, pipeline laying and offshore and onshore drilling services. The Company owes its market position to technological and operational skills which we believe are acknowledged in the marketplace due to its capabilities to operate in frontier areas and complex ecosystems, efficiently and effectively managing large projects, engineering competencies and availability of technologically-advanced vessels and rigs which have been upgraded in recent years through a large capital expenditure plan.

Our Engineering & Construction segment is expected to return to profitability in 2014 after a challenging 2013 which was severely hit by customer relationship and management issues. In 2013, management undertook business reorganization, refocused the operations and implemented a more selective marketing strategy. The outlook for 2014 is uncertain as an expected return to profitability depends on the speed at which new orders are acquired and the effective execution of contracts underway.

However management believes that medium to long-term prospects of the business remains sound.

Management expects to preserve Saipem s competitive position in the medium term, leveraging on its business model which is underpinned by an established competitive position in frontier areas, which are traditionally less exposed to the cyclical nature of this market. In particular, Saipem plans to implement the following strategic guidelines: (i) to maximize efficiency in all business areas at the same time maintaining top execution and security standards, preserve competitive supply costs, optimize the utilization rate of the fleet, increase structure flexibility in order to mitigate the effects of negative business cycles as well as develop and promote a company culture that will permit identification and management of risks and business opportunities; (ii) to continue focusing on the more complex and difficult projects in the strategic segments of deepwater, FPSO, heavy crude and LNG (offshore and onshore, for the gas monetization) upgrading; (iii) to promote local content in terms of employment of local contractors and assets in strategic countries where large projects are carried out supporting the development of delocalized logistic hubs and construction yards when requested by clients in order to achieve a long-term consolidation of its market position in those countries; (iv) to leverage on the capacity to execute internally more phases of large projects on an

EPC and EPCI basis, pursuing better control of costs and terms of execution adapting with flexibility to clients needs, thus expanding the Company s value proposition; and (v) to complete the expansion and revamping program of its construction and drilling fleet in consideration of the future needs of the oil&gas industry, in order to confirm the Company s leading position in the segment of complex projects with high profitability.

Saipem expects to invest approximately euro 2.8 billion over the next four years to complete the upgrading program of its fleet of vessels and rigs, further expanding the operational features, the dimension and the geographical reach of its fleet, as well as to support the activities related to the execution of projects in portfolio and the acquisition of new orders.

Orders acquired amounted to euro 10,653 million as of December 31, 2013 (euro 13,391 million as of December 31, 2012), of these projects to be carried out outside Italy represented 94%, while orders from Eni companies amounted to 14% of the total. Order backlog amounted to euro 17,514 million at December 31, 2013 (euro 19,739 million at December 31, 2012), of these projects to be carried out outside Italy represented 96%, while orders from Eni companies amounted to 13% of the total.

		2011	2012	2013
Orders acquired	(euro million)	**12,505**	**13,391**	**10,653**
Offshore Engineering & Construction		6,131	7,477	5,777
Onshore Engineering & Construction		5,006	3,972	2,566
Offshore Drilling		780	1,025	1,401
Onshore Drilling		588	917	909
Originated by Eni companies	(%)	7	5	14
To be carried out outside Italy	(%)	91	96	94
Order backlog and breakdown by business	(euro million)	**20,417**	**19,739**	**17,514**
Offshore Engineering & Construction		6,600	8,721	8,447
Onshore Engineering & Construction		9,604	6,701	4,436
Offshore Drilling		3,301	3,238	3,390
Onshore Drilling		912	1,079	1,241
Originated by Eni companies	(%)	14	13	13
To be carried out outside Italy	(%)	91	91	96

Offshore Engineering & Construction

Saipem is well positioned in the market of large, complex projects for the development of offshore hydrocarbon fields leveraging on its technical and operational skills, supported by a technologically-advanced fleet, the ability to operate in complex environments, and engineering and project management capabilities acquired on the marketplace over recent years. Saipem intends to consolidate its market share strengthening its EPCI oriented business model and leveraging on its satisfactory long-term relationships with the major oil companies and National Oil Companies (NOCs). Higher levels of efficiency and flexibility are expected to be achieved by reaching the technological excellence and the highest economies of scale in its engineering hubs employing local resources in contexts where this represents a competitive advantage, integrating in its own business model the direct management of construction process through the creation of a large construction yard in South-East Asia and revamping/upgrading its construction fleet. Following the completion of assets expansion program (fleet and yards) which has been carried out in the last years, 2014-2017 Saipem Investment Plan envisages a slowdown. Excluding the new construction yard in Brazil to be completed in 2014, capital expenditures will be mainly related to fleet maintenance/substitutions, major upgrades on offshore fleet (including investments to cope with HSE high standards), equipment for the execution of awarded/expected projects ("project specific") and investments in strategic areas ("local content").

Saipem s offshore construction fleet is made up by 35 vessels and a large number of robotized vehicles able to perform advanced sub-sea operations. Its major vessels are: (i) the Saipem 7000 semi-submersible dynamic positioned vessel, with 14 ktonnes of lift capacity, capable to lay pipelines using the J-lay technique to the maximum depth of 3,000 meters; (ii) the Field Development Ship 2 for the development of underwater fields in dynamically positioned vessel utilized for the development of deep-water fields, capable of launching pipes with a maximum diameter of 36 inches in J-lay mode with a holding capacity of up to 2,000 tonnes. Also capable of operating in S-lay mode with a lifting capacity of up to 1,000 tonnes; (iii) the Castoro Sei semi-submersible vessel, capable of laying pipes in waters up to 1,000 meters deep; (iv) the Saipem 3000 self-propelled dynamically positioned derrick crane ship, capable of laying flexible pipes and umbilicals in deep waters and of lifting structures weighing up to 2,200 tonnes; and (v) the Castorone self-propelled, dynamically positioned pipe-laying vessel operating in S-lay mode with a 120-meter long S-lay stern ramp composed of 3 articulated and adjustable stinger sections for shallow and deep-water operation, holding capacity of up to 750 tonnes (expandable to 1,000 tonnes), pipes size up to 60 inches, onboard fabrication facilities for triple on double joints and large pipe storage capacity in cargo holds.

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The most significant orders awarded in 2013 in Offshore Engineering & Construction were: (i) EPCI contract on behalf of Total Upstream Nigeria Ltd, for the development of the Egina field in Nigeria that includes engineering, procurement, fabrication, installation and pre-commissioning of subsea pipelines for oil and gas production and gas export, flexible jumpers and umbilicals; (ii) contract on behalf of Burullus Gas Co for the development of the West Delta Deep Marine - Phase IXa project, about 90 kilometers off the Mediterranean coast of Egypt. The project is aimed to the installation of subsea facilities (in water depths up to 850 meters) in the West Delta Deep Marine Concession, where Saipem had already successfully performed some previous phases of subsea field development; and (iii) EPCI contract on behalf of ExxonMobil pertaining to the engineering, procurement, fabrication and installation of subsea pipelines of production and water injection, rigid jumpers and other related subsea structures as part of Kizomba Satellites Phase 2 project, undertaken in the Angolan offshore.

As part of the Trunkline and Production Flowlines project committed by the North Caspian Sea Production Sharing Agreement Consortium in Kazakhstan (in which Eni retains an interest of 16.81%), which provided the engineering, laying and commissioning of pipelines and other facilities, following leakages that were detected in a section of the onshore pipelines, Saipem was requested by the clients to address the issue under the guarantee. Saipem, presuming not to be obliged to perform those works, has invited the client to investigate other possible causes of the issue identified. At present, no dispute is underway between Saipem and the Consortium.

Onshore Engineering & Construction

In the Onshore Engineering & Construction business, Saipem is one of the largest operators on turnkey contract base at a worldwide level in the oil&gas segment, especially through the acquisition of Snamprogetti. Saipem operates in the construction of plants for hydrocarbon production (extraction, separation, stabilization, collection of hydrocarbons, water injection) and treatment (removal and recovery of sulphur dioxide and carbon dioxide, fractioning of gaseous liquids, recovery of condensates) and in the installation of large onshore transport systems (pipelines, compression stations, terminals). Saipem preserves its own competitiveness through its technology excellence granted by its engineering hubs, its distinctive know-how in the construction of projects in the high-tech market of LNG and the management of large parts of engineering activities in cost efficient areas. In the medium term, underpinning upward trends in the oil service market, Saipem will be focused on taking advantage of the opportunities arising from the market in the plant and pipeline segments leveraging on its solid competitive position in the realization of complex projects in the strategic areas of Middle-East, Caspian Sea, Northern and Western Africa and Russia.

The most significant orders awarded in 2013 in Onshore Engineering & Construction were: (i) the EPC contract on behalf of Dangote Fertilizer for the realization of a new ammonia and urea production complex to be realized in Edo State, Nigeria. The contract encompasses the construction of two twin production streams and related utilities and off-site facilities; (ii) the EPC contract on behalf of Star Refinery AS, for the realization of Socar Refinery in Turkey, encompassing the engineering, procurement and construction of a refinery and three crude refinery jetties, to be built in the area adjacent to the Petkim Petrochemical facility; and (iii) the EPC contract for Eni related to the improvements to the storage infrastructure for crude oil of Tempa Rossa field, in Italy.

Offshore Drilling

Saipem is the only engineering and construction contractor that provides also offshore and onshore drilling services to oil companies. In the Offshore Drilling segment Saipem mainly operates in West Africa, the North Sea, Mediterranean Sea and the Middle East and boasts significant market positions in the most complex segments of deep and ultra-deep offshore, leveraging on the outstanding technical features of its drilling platforms and vessels, capable of drilling exploration and development wells at a maximum depth of 9,200 meters. In parallel, investments are ongoing to renew and to keep up the production capacity of other fleet equipment (upgrade equipment to the characteristics of projects or to clients needs and purchase of support equipment).

Saipem s Offshore Drilling fleet consists of 17 vessels fully equipped for its primary operations and some drilling plants installed on board of fixed offshore platforms. Its major vessels are: the Saipem 12000 and Saipem 10000, designed to explore and develop hydrocarbon reservoirs operating in excess of 3,600 and 3,000 meter water depth, respectively in full dynamic positioning. Other relevant vessels are Scarabeo 8 and 9, sixth generation semi-submersible rigs able to operate at depths of 3,000 and 3,600 meters of water, respectively. Average utilization of drilling vessels in 2013 stood at 100% (100% in 2012).

The most significant orders awarded in 2013 in Offshore drilling were: (i) five-year contract extension with Eni for the charter of the drillship Saipem 10000 starting from the third quarter of 2014 for worldwide drilling activity operations; (ii) one-year contract extension on behalf of IEOC, for the utilization of the semi-submersible Scarabeo 4 in

Egypt; and (iii) two-year contract extension on behalf of Eni for the charter of the Saipem TAD for drilling activity offshore Congo.

Onshore Drilling

Saipem operates in this area as a main contractor for the major international oil companies and NOCs executing its activity mainly in South America, Saudi Arabia, North Africa and, at a lower extent, in Europe. In this area Saipem can leverage its knowledge of the market, long-term relations with customers and synergies and integration with other business areas. Saipem boasts a solid track record in remote areas (in particular in the Caspian Sea), leveraging on its own operational skills and its ability to operate in complex environments.

Average utilization of rigs in 2013 stood at 96% (97.2% in 2012). The 96 rigs (in addition to 1 rigs under completion) owned by Saipem at year end were located as follows: 28 in Venezuela, 20 in Saudi Arabia, 19 in Peru, 7 in Colombia, 5 in Kazakhstan, 4 in Bolivia, 3 in Ecuador, 2 in Algeria, 2 in Chile, 1 in Congo, 1 in Italy, 1 in Ukraine, 1 in Mauritania, 1 in Turkey and 1 in Morocco and Saipem also used rigs owned by third parties (6 in Peru, 3 in Kazakhstan, 1 in Ecuador and 1 in Congo), as well as rigs owned by the joint company Saipar.

The most significant orders awarded in 2013 in Onshore drilling were: (i) a contract on behalf of Saudi Aramco for the lease of 15 facilities for a term ranging from three to five years in Saudi Arabia; and (ii) the contracts for 8 facilities to be employed in South America, Saudi Arabia, Kazakhstan, Algeria, Mauritania and Italy for periods ranging from 2 months to two years.

Capital expenditures

See "Item 5 Liquidity and capital resources Capital expenditures by segment".

Chemicals

Eni operates in the businesses of olefins and aromatics, basic and intermediate products, polystyrene, elastomers and polyethylene. Its major production sites are located in Italy and Western Europe. These are predominantly oil-based businesses with a history of losses and poor growth prospects. In fact, we face structural headwinds in our legacy basic petrochemical and plastic businesses due to the commoditized nature of our products, low entry barriers, lack of scale, exposure to the volatility in the costs of oil-based feedstock, cyclicality in demand, and strong competitive pressures from operators with lower cost structure especially from the Middle and Far East, Asia and other weaknesses. Eni s profitability in the petrochemical businesses is particularly sensitive to movements in product margins that are mainly affected by changes in oil-based feedstock costs and the speed at which product prices adjust to higher oil prices. See "Item 3 Risk factors".

In 2013, the Chemical segment continued to report operating losses which reflected the prolonged demand weakness due to the economic downturn in Europe and margin pressure due to competition and high crude oil costs. Management does not expect any improvements in trading environment for the foreseeable future as demand weakness due to macroeconomic uncertainties, competition from Far East and Middle East producers and high crude oil costs will affect future results of operations and cash flow.

Against this backdrop, management is seeking to turn around the Company s chemical operations in order to reduce its exposure to loss-making lines of business in basic petrochemicals and plastics by further restructuring and closing unprofitable plants and units and other efficiency initiatives. To reshape our product portfolio we are also refocusing our efforts and resources on niche segments where we expect to have competitive advantages driven by proprietary technologies and on the business of green chemicals where we expect to capture opportunities for growth and profitability. Management believes that the planned initiative to turn around the business will be able by the end of the plan period to offset structural headwinds in our legacy basic petrochemical and plastic businesses as we expect to break even by the end of the plan period, assuming no improvement in the scenario.

As part of our turn around strategy, we intend to grow the green chemistry business leveraging on the initiatives underway. The most important is the restructuring of the Porto Torres plant where we have shut down the production of basic petrochemicals and we are progressing the construction of new facilities for the production of green chemicals which are products with an elevated bio-degradability rate and/or produced from raw materials obtained from renewable sources. Other initiatives include the restructuring of the loss-making Porto Marghera cracking unit where Eni expects to invest euro 200 million focused on the optimization and reorganization of cracker utilities, with significant energy savings, and on the new initiative of green chemistry. An innovative green chemistry project will be launched at Porto Marghera in partnership with the U.S. company Elevance Renewable Science Inc, whereby the two partners will jointly develop world-scale plants based on a new technology for the production of bio-chemical intermediates and vegetable oils for sectors with high added value applications such as detergents, bio-lubricants and chemicals for the oil industry. The project will take advantage of existing infrastructures.

Eni also intends to grow the production and sales of elastomers and other niche products where we believe we retain a competitive advantage due to our proprietary technologies. As part of this plan, we have recently signed strategic alliances with industrial operators in Malaysia and South Korea to build and operate plants for the production of elastomers which will destined to the growing East Asian consumer markets. To better differentiate our elastomers and to reduce the production costs in 2013, we signed strategic partnerships with U.S. operators Genomatica and Yulex in order to jointly develop and license new technologies for the manufacturing on an industrial scale of elastomers based on renewable feedstock and other vegetable, non-food stuff.

The Company will also continue to leverage on efficiency actions to reduce operating costs and on the rationalization program of our plants in order to improve yields and efficiency, restructuring unprofitable sites, in particular cutting the Company s ethylene and polyethylene capacity.

Management plans to make selective capital expenditures amounting to approximately euro 1.9 billion over the next four year. The main investment will target the conversion of the Porto Torres unit in Sardinia, Italy, into an innovative bio-based chemical complex to produce bio-plastics and other bio-based chemical products, and the Porto Marghera project. In addition, the Company plans to develop the elastomers businesses by contributing to the agreed joint ventures projects in East Asia, upgrade and revamp the Company s cracking units as well as complying with all applicable regulations on environment, health and safety issues.

In 2013, sales of chemical products (3,785 ktonnes) decreased by 168 ktonnes from 2012 (down by 4.3%) against of backdrop of weakness demand reflecting the current economic downturn in the main reference markets. The steepest decline was registered in elastomers (down by 9.7%) and in intermediates (down by 4.2%). Lower reduction was reported in polyethylene (down by 3%) and in styrenes (down by 2.9%).

Chemical production (5,817 ktonnes) decreased by 273 ktonnes from 2012, or 4.5%. This was mainly due to a decrease in elastomers (down by 11%). Lower decreases were registered in styrenes (down by 2.8%), in polyethylene (down by 6%) and in intermediates (down by 3.7%). The main decreases in production were registered at the Priolo plant (down by 8.4%) due to the planned standstill of olefin cracking plant and the definitive shutdown of Ragusa polyethylene plant (down by 12.5%) due to lower volumes of polyethylene. These reductions were partly offset by higher production at Sarroch (up by 11.6%), which in 2012 was impacted by the standstill for the planned upkeeping as well as higher levels of benzene and xiloli production.

Outside Italy, production decreased at the Dunkerque site (down by 5.3%) driven by the weakness of polyethylene market as well as planned standstill in the second half of the year. Nominal capacity of plants declined from the previous year due to the shutdown of Ragusa plant, while the average plant utilization rate, calculated on nominal capacity, was 65.3% (66.7% in 2012).

The table below sets forth Eni s main chemical products availability for the periods indicated.

	Year ended December 31,		
	2011	2012	2013

		(ktonnes)	
Intermediates	3,624	3,595	3,462
Polymers	2,621	2,495	2,355
Total production	**6,245**	**6,090**	**5,817**
Consumption and losses	(2,631)	(2,545)	(2,394)
Purchases and change in inventories	426	408	362
	4,040	**3,953**	**3,785**

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The table below sets forth Eni s main petrochemical products revenues for the periods indicated.

	Year ended December 31,		
	2011	2012	2013
	(euro million)		
Intermediates	2,987	3,050	2,709
Polymers	3,299	3,188	2,933
Other revenues	205	180	217
Total revenues	**6,491**	**6,418**	**5,859**

Intermediates

Intermediates revenues (euro 2,709 million) decreased by euro 341 million from 2012 (down by 11.2%) reflecting decreased volumes sold (down by 4.2%) and average unit prices (down by 1.9%), with different trends in each business: in the olefins sales volumes of ethylene decreased (down by 4%) due to the planned standstill at the Priolo plant and lower consumption, with prices slightly decreasing compared to previous year, while butadiene volumes reported a sharp decrease (down by 38%) driven by the weakness of elastomers market and the reduced average prices by 23% reflecting the consumption crisis. In aromatics, benzene sales volumes registered a decline of 7.4%, while xylene volumes increased by 7.5%, with average prices in line with 2012. Revenues from derivatives declined mainly due to lower volumes of phenol/derivatives (down by 3.6%) due to lower availability of product following planned downtime at the Mantova plant, partly offset by 1.4% increase in average sale prices.

Intermediates production (3,462 ktonnes) registered a decrease from the last year (down by 133 ktonnes, or 3.7%) due to reductions in olefins (down by 5.7%) and in derivatives (down by 2.4%) driven by lower utilization of Priolo cracking plant and lower production of butadiene (down by 10.3%) affected by the planned facility downtimes at the Brindisi and Ravenna plants.

These reductions were partly offset by higher aromatics production (up by 3% compared to the previous year) due to higher xylene production.

Polymers

Polymers revenues (euro 2,933 million) decreased by euro 255 million from 2012, or by 8%, due to average unit prices decreasing by 19% and lower elastomers sale volumes (down by 9.7%) due to the significant decrease in demand from the tire and automotive industry.

This negative performance was partly offset by higher average prices of styrene (up by 7.5%) and polyethylene (up by 1%) mainly registered in the last part of 2013.

Polymer production (2,356 ktonnes) decreased by 140 ktonnes from 2012 (down by 5.6%), due mainly to a decline in production at the Ravenna plant and at English sites (Hythe and Grangemouth).

Capital expenditures

See "Item 5 Liquidity and capital resources Capital expenditures by segment".

Corporate and Other activities

These activities include the following businesses:

the "Other activities" segment comprises results of operations of Eni s subsidiary Syndial which runs minor petrochemical activities and reclamation and decommissioning activities pertaining to certain businesses which Eni exited, divested or shut down in past years; and

the "Corporate and financial companies" segment comprises results of operations of Eni s headquarters and certain Eni subsidiaries engaged in treasury, finance and other general and business support services. Eni s headquarters is a department of the parent company Eni SpA and performs Group strategic planning, human resources management, finance, administration, information technology, legal affairs, international affairs and corporate research and development functions. Through Eni s subsidiaries Eni Adfin SpA, Eni Finance International SA, Banque Eni SA, Eni International BV, Eni Finance USA Inc and Eni Insurance Ltd, Eni carries out cash management activities lending, factoring, leasing, financing Eni s projects around the world and insurance activities, principally on an intercompany basis. EniServizi, Eni Corporate University, AGI and other minor subsidiaries are engaged in providing Group companies with diversified services (mainly services including training, business support, real estate and general purposes services to Group companies). Management does not consider Eni s activities in these areas to be material to its overall operations.

Seasonality

Eni s results of operations reflect the seasonality in demand for natural gas and certain refined products used in residential space heating, the demand for which is typically highest in the first quarter of the year, which includes the coldest months and lowest in the third quarter, which includes the warmest months. Moreover, year-to-year comparability of results of operations is affected by weather conditions affecting demand for gas and other refined products in residential space heating. In colder years that are characterized by lower temperatures than historical average temperatures, demand for gas and products is typically higher than normal consumption patterns, and vice versa.

Research and development

Technological research and development (R&D) and continuous innovation represent key success factors in implementing Eni s business strategies as they support our long-term competitive performance.

The Company believes that the oil&gas industry will continue to face several challenges which are far to be solved:
- uncertainty about oil&gas prices and demand;
- limited access to new hydrocarbon resources, with increasing role of "difficult" oil&gas basins;
- attention to a more efficient exploitation of renewable sources for energy production; and
- last but not the least, safety of operations as a crucial point for business success.

In order to address the above challenges, Eni will strongly pursue the following technological targets in the next future:
- increasing the capability to exploit deepwater fields (deeper than 3,000 m) as well as arctic and unconventional assets;
- scale up of innovative technologies aimed at increasing operational safety, with particular respect to the upstream sector;
- assessing the impact of innovative small-scale LNG technologies on gas consumption increase both in the industrial and commercial sectors;
- enhancing technological developments for the efficient use of energy in mid and retail markets (co-generation, energy storage, smart metering and integration with renewable energy sources);
- scale up of proprietary technologies in downstream oil (e.g. T-Sand, Zero Waste);
- defining the best technological solutions for the conversion of 2nd generation bio-mass into bio-diesel at Venice refinery;

- development of innovative technologies for the efficient conversion of bio-mass into polymers, elastomers and other renewable chemical products; and
- development of innovative environmental technologies for in situ bio-remediation.

In 2013, Eni filed 59 patent applications (74 in 2012), 36 of these coming from Eni s segments and Eni Corporate, 9 from Versalis and 14 from Saipem.

In 2013, Eni s overall expenditure in R&D amounted to euro 197 million which were almost entirely expensed as incurred (euro 211 million in 2012 and euro 190 million in 2011).

In February 2013, the agreement between Eni and MIT was renewed for 4 years and a total amount of at least $20 million.

At December 31, 2013, a total of 986 persons were employed in research and development activities.

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Below, we describe the main results achieved in the development and application of innovative technologies in 2013.

Exploration & Production

- *e-rabbit*™. The proprietary computation code based on genetic algorithms is able to address operational interferences in complex production systems. The implementation of this code at Val d Agri field in Italy allowed to increase the hydrocarbon production by 2%.

- *extreme-lean profile (x-lp™).* The proprietary drilling technology allows a faster rock penetration as well as the reduction of drilling debris by 50% and of cement for well-casing by 30%. This technology was applied in 2013 for the construction of seven wells on the EPC-4 island in Kazakhstan.

- *eni-Depth Velocity Analysis (e-dva™).* The discovery of the gas field "Mamba" in Mozambique leveraged on the implementation of the new proprietary workflow which combines the study of anisotropy with data processing and the analysis of seismic signal amplitude.

Gas & Power

- *Eni Kassandra Meteo Forecast (e-km™).* Since 2009, Eni has been developing a short long-term proprietary meteorological forecast system in collaboration with Epson Meteo, which can be used for managing energy resources and improving the power generation process. This system for forecasting temperatures trend on global and regional scale, from 1 to 90 days, provides an innovative solution towards statistical systems. In 2013, the system was further developed to expand the geographical coverage in Europe (Italy, Belgium, Germany and France), and it was used by all EniPower s power plants for their thermo-electric production.

- *Eni Vibroacoustic Pipeline Monitoring System (e-vpms™).* The Eni proprietary technology allows a continuous detection of third-party intrusions and leaks in fluid-filled pipelines (gas, water, crude oil and refinery products pipeline) by a remote control station. In 2013, the technology was successfully implemented also in Eni s Exploration & Production and Refining & Marketing contexts.

Refining & Marketing

- *Eni Slurry Technology (EST).* In 2013, the first EST industrial plant began to operate at Eni s Sannazzaro de Burgondi refinery. The R&D activities supported the optimization of input selection and output production. Eni also evaluated the possibility to license out the technology to other oil companies interested into EST implementation at their own refineries or into the enhancement of heavy oil reserves. At the same time, the development of the proprietary Slurry Dual-Catalyst technology continued for the selection of two combined catalysts able to improve EST performance, in terms of product quality and cost reduction.

- *T-Sand.* In 2013, Eni carried on the development of this innovative catalytic system for hydrotreating/ dearomatization which allows the production of high quality gasoil, with low poly-aromatic content and particulate emissions. The technology industrial test run will take place at Gela refinery in the first half of 2014.

- *Zero Waste.* The technology is based on a thermal process for the treatment of industrial oily and biological residues generated by the petroleum industry production activities. The process was validated on a pilot scale plant. The main environmental benefits obtained are: (i) a reduction of the waste to be disposed higher than 90%; and (ii) a production of a syngas capable both to thermally self-support the process and (in case of surplus with respect to the self-sustaining) to recover hydrocarbons from the sludge. The first prototype based on this technology, with a capacity of 2 tonnes/h, is under construction at Eni s Gela refinery.

Versalis

- *Joint venture with Genomatica for the conversion of renewable bio-mass into butadiene.* In April 2013, Versalis and Genomatica signed a joint-venture agreement for the development of a proprietary technology for the conversion of non-food bio-mass into butadiene. The new joint venture will hold exclusive rights on the use of the technology in Europe, Asia and Africa. The future licensees, including Versalis, will be responsible for the capital expenditure needed to build up proprietary plants, operation management, use and sales of produced butadiene.

- *Agreement with Pirelli for joint R&D activities on the use of natural rubber from guayule for tires production.* In March 2013, Versalis and Pirelli signed an important Memorandum of Understanding aimed at starting a joint research project lasting three years during which Versalis will provide innovative kinds of rubbers produced from guayule. These rubbers will be tested by Pirelli targeting tires production.

Eni Corporate

- *Conversion of bio-mass into bio-diesel.* In 2013, Eni Corporate and Refining & Marketing Division started a collaboration to implement the proprietary technology for bio-mass conversion into 2nd generation bio-fuels at Venice bio-refinery.

- *Environment.* Eni is about to complete the construction of its "technology laboratory" leveraging on in-house tools and know-how for a better definition of the remediation plan of contaminated sites, in order to increase the value added by Syndial s activities.

Insurance

In order to control the insurance costs incurred by each of Eni s business units, the Company constantly assesses its risk exposure in both Italian and foreign activities. The Company has established a captive subsidiary, Eni Insurance Ltd, in order to efficiently manage transactions with mutual entities and third parties providing insurance policies. Internal insurance risk managers work in close contact with business units in order to assess potential underlying business and other types of risks and possible financial impacts on the Group results of operations and liquidity. This process allows Eni to accept risks in consideration of results of technical and risk mitigation standards and practices, to define the appropriate level of risk retention and, finally, the amount of risk to be transferred to the market.

Eni enters into insurance arrangements through its shareholding in the Oil Insurance Ltd (OIL) and with other insurance partners in order to limit possible economic impacts associated with damages to both third parties and the environment occurring in case of both onshore and offshore accidents. The main part of this insurance portfolio is related to operating risks associated with oil&gas operations which are insured making use of insurance policies provided by the OIL, a mutual insurance and re-insurance company that provides its members a broad coverage of insurance services tailored to the specific requirements of oil and energy companies. In addition, Eni makes recourse to insurance companies who we believe are established in the marketplace. Insured liabilities vary depending on the nature and type of circumstances; however underlying amounts represent significant shares of the plafond granted by insuring companies. In particular, in the case of oil spills and other environmental damage, current insurance policies cover costs of cleaning-up and remediating polluted sites, damage to third parties and containment of physical damage up to $1.1 billion for offshore events and $1.5 billion for onshore plants (refineries). These are complemented by insurance policies that cover owners, operators and renters of vessels with the following maximum amounts: $1 billion for the fleet owned by the subsidiary LNG Shipping in the Gas & Power segment and FPSOs used by the Exploration & Production segment for developing offshore fields; $500 million for time charters.

Management believes that the level of insurance maintained by Eni is generally appropriate for the risks of its businesses. However considering the limited capacity of the insurance market, we believe that Eni could be exposed to material uninsured losses in case of catastrophic incidents, like the one occurred in the Gulf of Mexico in 2010 which could have a material impact on our results and liquidity. See "Item 3 Risk factors Risk associated with the exploration & production of oil and natural gas".

Environmental matters

Environmental regulation

Eni is subject to numerous EU, international, national, regional and local environmental, health and safety laws and regulations concerning its oil and gas operations, products and other activities, including legislation that implements international conventions or protocols. In particular, these laws and regulations require the acquisition of a permit before drilling for hydrocarbons may commence, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with exploration, drilling and production activities, limit or prohibit drilling activities on certain protected areas, provide for measures to be taken to protect the safety of the workplace and health of communities affected by the Company s activities, and impose criminal or civil liabilities for pollution resulting from oil, natural gas, refining and petrochemical operations. These laws and regulations may also restrict emissions and discharges to surface and subsurface water resulting from the operation of natural gas processing plants, petrochemical plants, refineries, pipeline systems and other facilities that Eni owns. In addition, Eni s operations are subject to laws and regulations relating to the production, handling, transportation, storage, disposal and treatment of waste materials. Environmental laws and regulations have a substantial impact on Eni s operations. Some risk of environmental costs and liabilities is inherent in certain operations and products of Eni, and there can be no assurance that material costs and liabilities will not be incurred. See "Item 3 Risk factors".

We believe that the Company will continue incurring significant amounts of expenses to comply with pending regulations in the matter of environmental, health and safety protection and safeguard, particularly to achieve any mandatory or voluntary reduction in the emission of greenhouse gases (GHG) in the atmosphere and cope with climate change.

A brief description of major environmental, health and safety laws impacting Eni s activities located in Italy and European Union is outlined below.

Italy

The Italian Environmental Code approved by Legislative Decree No. 152 of April 3, 2006, sets up the basic rules for environmental protection regulating: the Environmental Impact Assessment (EIAs), the Integrated Prevention and Pollution Control (IPPC), procedures for Strategic Environment Assessment, soil and water protection, air pollution and reduction of emissions, waste management and remediation of contaminated sites, environmental liability and sustainable development. Particularly, the Environmental Code requires that reclamation and remediation activities be performed on the basis of a site-specific risk-based approach to determine objectives of reclamation and remediation projects, cost-effective analysis to evaluate remediation solutions, and criteria for waste classification. In 2012, the application of the Integrated Environmental permit under IPPC regulation was extended to all off-shore Italian platforms.

Legislative Decree No. 231 of June 8, 2001, as amended by Legislative Decree No. 121 of July 7, 2011, which provides for monetary sanctions for legal entities in cases of criminal offences concerning the environment. This decree introduced into Italian law the liability of legal entities in relation to the crimes committed by employees against the environment. Particularly, the Italian legislator broadened the scope of corporations liabilities for the crimes committed by employees to include crimes relating the illicit discharge of industrial waste water, violations in reporting, record keeping and other omitted evidence in the matter of waste, unauthorized waste management, illegal trafficking of waste, as well as crimes relating the application in Italy of the Convention on International Trade in animal and plant species threatened with extinction, violations of measures intended to protect stratospheric ozone and the environment and pollution caused by ships.

Decree No. 155/2010 adopted in the Italian law the European prescriptions on ambient air quality, established by the Directive No. 2008/50/EC. Its main innovation is the definition of monitoring criteria and emission limits for fine particulate substances (PM 2.5), to be achieved by January 1, 2015. On February 12, 2013, Legislative Decree No. 250/2012 amending Legislative Decree No. 155/2010 transposing Directive No. 250/2008/EC on air quality entered in force. The changes introduced by the new decree were necessary to overcome some critical points appeared in the first phase of application of the new discipline and to better regulate the relations with local governments and to better define the role of the Institute for Environmental Protection and Research.

Italy has regulated the Emission Trading System by Legislative Decree No. 30 of March 13, 2013, transposing requirements of Directive No. 2009/29/EC (amending Directive No. 2003/87/EC to extend the Community trading system of CO_2 emission). The cited Decree replaces the former Decree No. 216/2006.

Decree No. 101/2013, Article 11, reviewed the legislative framework on SISTRI, an automated tracking system of hazardous waste, which aims at real time monitoring of the routes of wastes and at prosecuting any unlawful act in waste management: according to Decree No. 101/2013, SISTRI entered into force partially on October 1, 2013. The period until December 31, 2014 will be experimental, since the previous obligations shall remain mandatory, while the sanctions for SISTRI shall be applied only from January 1, 2015. An important revision of the SISTRI regulations should take place by 2014.

Legislative Decree No. 81/2008 concerned the protection of health and safety in the workplace and was designed to regulate the work environments, equipments and individual protection devices, physical agents (noise, mechanical vibrations, electromagnetic fields, optical radiations, etc.), dangerous substances (chemical agents, carcinogenic substances, etc.), biological agents and explosive atmosphere, the system of signs, video terminals. Eni worked on the implementation of the general framework regulations on health and safety concerning prevention and protection of workers at national and European level to be applied to all kinds of workers and employees.

Italian local authorities are appealing more often to Health Impact Assessment (HIA) and are integrating this procedure with Environmental Impact Assessment and Strategic Impact Assessment (SIA). During 2012, a strong correlation has been observed between health issues and environmental aspects. In fact, various HIA, SIA and EIA methodologies are being developed as a unique regulation (e.g. Cervellera Law in Puglia Region). In August 2013, has been published in the official journal, April 24, 2013 Decree establishing the methodological criteria for preparing the reports of health damage assessment (VDS) in implementation of Decree ILVA (Law Decree No. 207/2012 converted Law No. 231/2012). Eni is involved in an internal multidisciplinary project on health and environmental assessment of plants impacts.

The complexity and scale of situations and contexts where Eni is operating requires the adoption of business processes, guidelines and principles for improving its performance in health and prevention. To this end Eni upholds:

- clear policies;
- an ethical code;
- endorsement of international conventions and principles;
- guidelines and procedures; and
- sharing of knowledge.

European Union

On June 21, 2012, the Commission adopted two Regulations on monitoring and reporting of GHG emissions and on verification and accreditation of verifiers under the EU Emissions Trading System. Both Regulations form part of the set of implementing rules for the third trading period of the EU ETS and entered in force in January 2013.

On July 20, 2012, Regulation EU No. 530/2012 on the accelerated phasing-in of double-hull or equivalent design requirements for single-hull oil tankers entered in force. The new Regulation prohibits the transport to or from EU ports of heavy grades of oil in single-hull oil tankers as decided by the Marpol Convention 73/78.

On March 12, 2014, the European parliament gave its final approval on a new EIA Directive (Environmental Impact Assessment). The scope of the new directive is to facilitate the assessment of potential impacts, without weakening existing environmental safeguards and to reinforce the decision-making process and improve current levels of environmental protection. Moreover a new document updates EIA with emerging challenges in areas like resource efficiency, climate change, bio-diversity and disaster prevention that will be reflected in the assessment process. The new directive should be soon formally approved on the Council of the European Ministers and published in the Official Journal.

On December 20, 2013, the European parliament, Commission and the technical committee have achieved a compromised agreement on the text for the new EIA Directive. The new text intends to facilitate the assessment of potential impacts, without weakening existing environmental safeguards and to reinforce the decision-making process and improve current levels of environmental protection. Moreover, a new document updates EIA with emerging challenges in areas like resource efficiency, climate change, bio-diversity and disaster prevention that will be reflected in the assessment process. In particular, a revised directive introduces in the list of made subject to EIA exploration and hydraulic fracturing extraction activities for non-conventional hydrocarbons (shale gas and oil, tight gas , coal bed methane), regardless of the amount extracted. The compromise agreement means that the text now will be formally approved by the European Parliament by May 2014.

On December 18, 2013, European Commission has adopted a Clean Air Policy Package for Europe that updates existing legislation and further reduces harmful emissions from industry, traffic, energy plants and agriculture, with a view to reducing their impact on human health and the environment. The package introduces measures to ensure that existing targets are met in the short term, and new air quality objectives for the period up to 2030. The package also includes support measures to help cut air pollution, with a focus on improving air quality in cities, supporting research and innovation, and promoting international cooperation. In addition, the new EU air policy proposes to revise

National Emission Ceilings Directive with stricter national emission ceilings for the six main pollutants and a proposal for new Directive to reduce pollution from medium-sized combustion installations, such as energy plants for street blocks or large buildings, and small industry installations.

On December 18, 2013, European Parliament and Council have achieved an agreement on a draft regulation on fluorinated greenhouse gases (F-gases). The agreed regulation will allow to reduce F-gas emissions by two-thirds of today s levels by 2030. It establishes rules regarding containment, use, recovery and destruction of those gases. In addition, the new law imposes conditions on the placing on the market of products and equipment containing or relying upon F-gases, whilst setting out quantitative limits for the placing on the market of hydrofluorocarbons (HFC).

On September 13, 2013, has entered in force a new directive on monitoring priority substances in water (directive 2013/39/EU). According to the new directive, twelve new substances were added to the list of the priority substances, and there will be stricter standards for seven substances already on the list.

In January 2014, the European Commission published Recommendation of minimum requirements on shale gas to ensure that proper environmental and climate safeguards are in place for "fracking". The Recommendation should help

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all Member States wishing to use this practice address health and environmental risks and improve transparency for citizens.

On January 1, 2013, as required by the Directive No. 2009/29/EC, started the third period of EU-ETS (2013-2020).

On March 27, 2013, the European Commission adopted the Green Paper on 2030 framework for climate and energy policies COM(2013) 169 with the aim of starting the debate about the long-term policy perspectives of Europe. On the same day a public consultation was launched and has been run until July 2, 2013.

On June 28, 2013, the European Commission set out a strategy for progressively integrating maritime emissions into the EU s policy for reducing its domestic GHG emissions COM(2013) 479 final . At the same time the Commission put forward a legislative proposal COM(2013) 480 final to establish an EU system for Monitoring, Reporting and Verifying (MRV) emissions from large ships using EU ports. The Commission proposes that the MRV system apply to shipping activities carried out from January 1, 2018. To become law, the proposal requires approval by the European Parliament and Council.

On September 5, 2013, the European Commission adopted two Decision related to the third phase functioning of EU-ETS: Decision No. 2013/447/EU, that set out the Standard Capacity Utilization Factors per each product benchmark listed Annex I to Decision No. 2011/278/EU, and Decision No. 2013/448/EU, that introduce the values of Cross Sectoral Correction Factor (CSCF) for each year of the third period EU-ETS. The CSCF is a coefficient aimed to decrease the amount of free industrial allocation in order to maintain the total amount of free quotas above a predefined cap (so-called industrial cap).

On January 22, 2014, following the stakeholders responses to the public consultation on Green Paper, the European Commission adopted the White Paper on a policy framework for climate and energy COM(2014) 15 in the period from 2020 to 2030. The current proposal contains a GHG domestic reduction target of -40% versus 1990 level, an objective of increasing the share of renewable energy to at least 27% of the EU s energy consumption by 2030 and qualitative targets on energy efficiency. In the same package the European Commission proposes also to establish from 2021 a so-called Market Stability Reserve COM(2014) 20 on the Emission Trading Scheme, to address the surplus that has built up in recent years.

On January 25, 2014, in the context of Emission Trading Scheme, was adopted the Regulation No. 176/2014, that postpone the auctioning of 900 million allowances until 2019-2020. In 2014, the total European auction volume will be reduced by 400 million allowances, in 2015 by 300 million, and in 2016 by 200 million. This short-term measure is aimed at rebalancing the supply and the demand of the European carbon market. This measure was made possible after the amendment of the ETS Directive approved in December 2013 (Decision No. 1359/2013/EU), which clarifies that the timing of allowances auctions may be changed to ensure the orderly functioning of the carbon market.

On December 4, 2012, the European Union Directive No. 2012/27/EU on energy efficiency entered in force; it establishes a common framework of measures for the promotion of energy efficiency within the Union in order to ensure the achievement of the EU s 20-20-20 headline target on energy efficiency. New measures include a legal definition and quantification of the EU energy efficiency target. The Member States are obliged to set an indicative national energy efficiency target, to establish an obligation for large enterprises to carry out an energy audit at least every four years. The Directive gives also indications to improve efficiency in power generation.

The Directive is a game-changer for energy distributors or all retail energy sales companies, which are now required to achieve 1.5% energy savings every year among their final clients. Most of provisions of the Directive will have to be implemented by the EU Member States by June 5, 2014.

On June 1, 2007, the REACH regulation of the European Union (EC No. 1907/2006 of December 18, 2006) entered into force. REACH stands for Registration, Evaluation, Authorization and Restriction of Chemicals and was adopted to improve the protection of human health, safety and the environment from the risks that can be posed by chemicals, while enhancing the competitiveness of the EU chemical industry. It also promotes alternative methods for the assessment of hazardous substances in order to reduce the number of tests on animals. REACH places the burden of proof on companies. To comply with the regulation, companies must identify and manage the risks linked to the substances they manufacture and market in the EU. They have to demonstrate to European Chemicals Agency (ECHA) how the substance can be safely used and they must communicate the risk management measures to the users. If the risks cannot be managed, authorities can restrict the use of substances in different ways. Over time, the hazardous substances should be substituted with less dangerous ones. The deadline of REACH registration depends on the tonnage band of a substance and the classification of a substance; next and last deadline is 2018. Eni recognizes the importance of the Regulation REACH (CE) 1907/2006, the general principles of which are already an intrinsic part of the Company s commitment to sustainability and are an integral part of the culture and history of the Company. The compliance with the REACH requirements and the involvement of all the interested parties in the Company are coordinated and supervised by the HSEQ function. In particular, Eni is involved in the registration of substances and compounds to ECHA that regards a complex series of information about the characteristics of such substances and their uses and in another fundamental aspects that concerns the exchange of information between producers and importers, as well as the users of chemical substances ("downstream users").

The CLP Regulation (Classification, Labeling and Packaging) entered into force in January 2009 (Regulation EC No. 1272/2008 on the classification, labeling and packaging of substances and mixtures), and the method of classifying and labeling chemicals introduced is based on the United Nations Globally Harmonized System. The Regulation will replace two previous pieces of legislation, the Dangerous Substances Directive and the Dangerous Preparations Directive. There is a transition period until 2015. The CLP Regulation ensures that the hazards presented by chemicals are clearly communicated to workers and consumers in the European Union through classification and labeling of chemicals. Before placing chemicals on the market, the industry must establish the potential risks to human health and the environment of such substances and mixtures, classifying them in line with the identified hazards. The hazardous chemicals also have to be labeled according to a standardized system so that workers and consumers know about their effects before they handle them.

On December 17, 2010, the Directive No. 2010/75/EC on industrial emissions (IED) was published in the Official Journal of the European Union No. 334. The objective of the new Directive is to avoid or to minimize polluting emissions in the atmosphere, water and soil, as well as waste from industrial and agricultural installations, and to achieve a high level of environmental and health protection. The Directive brings together the IPPC Directive (Directive No. 2008/1/EC) and six other sector-specific Directives (Large Combustion Plants, VOC Volatile Organic Compounds emissions, incineration of waste and titanium industry). The Directive contains special provisions for the combustion plants with thermal input below 50 MW. Any industrial installation which carries out the activities listed in Annex I must meet certain obligations, as preventive measures taken against pollution, minimum emission values, apply the Best Available Techniques (BAT), monitoring rules and permit and reporting conditions. The Article 14 of the new Directive defines the permit necessary measures (as emission limit values for polluting substances, rules guaranteeing protecting of soil, water and air, suitable emission monitoring measures, waste monitoring and management measures, communication of monitoring results to the competent national authorities, requirements concerning the maintenance and surveillance of soil and groundwater, measures relating to exceptional circumstances as leaks, malfunctions, momentary or definitive stoppages, etc.). The Directive defines more restricting emission limits to be observed by the end of 2012, although includes some derogation, as the Transitional National Plan (TNP) and the option Opt-Out for those installations that are going to shut down their operations by 2023. On February 28, 2011, the European IPPC Bureau (EIPPCB) started the review process of the Reference Documents on Best Available Techniques for Large Combustion Plants "BREF-LCP" and in 2012 the consultation process was completed. On February 10, 2012, the Commission approved an implementing Decision No. 2012/119/EU laying down rules concerning guidance on the collection of data and on the drawing up of BAT reference documents and on their quality assurance referred to in Directive No. 2010/75/EU. Also in February 2012, the Commission implementing decision laying down rules concerning the transitional national plans referred to in Directive No. 2010/75/EU was published. Moreover in 2012, the EIPPCB published the Draft 2 Refining Bref and related BAT conclusion, which will be completed by the end of 2013 with the BAT conclusion. The Member States have to transpose the IED Directive into national legislation by December 2012. The Italian Government will adopt the IED directive into the Legislative Decree No. 152/2006 "Environment Regulation".

Following the incident at the Macondo well in the Gulf of Mexico the U.S. Government and other governments have adopted more stringent regulations targeting safety and reliable oil and gas operations in the United States and elsewhere, particularly relating to environmental and health and safety protection controls and oversight of drilling operations, as well as access to new drilling areas. Italian Authorities as well have passed legislation with Law Decree No. 128 on June 29, 2010 that introduces certain restrictions to activities for exploring and producing hydrocarbons, that have been confirmed and further geographically limited by the successive Law Decree No. 134 of August 7, 2012 and by the Ministerial Decree of September 4, 2013.

Also the European institutions have increased their activities in the area of environmental protection in the field of hydrocarbon extraction.

At European level on June 12, 2013, the Directive No. 2013/30/EU has been issued with the purpose to replace the existing National Legislations and uniform the legislative approach at European level. The main elements of the EU directive are the following:

- The Directive introduces licensing rules for effective prevention of and response to a major accident. The licensing authority in Member States will have to make sure that only operators with proven technical and financial capacities are allowed to explore and produce oil and gas in EU waters. Public participation is expected before exploratory drilling starts in previously un-drilled areas.
- Independent national competent authorities, responsible for the safety of installations, will verify the provisions for safety, environmental protection, and emergency preparedness of rigs and platforms and the operations conducted on them. Enforcement actions and penalties will be implemented if companies do not respect the minimum standards.
- Obligatory emergency planning calls for companies to prepare reports on major hazards, containing an individual risk assessment and risk-control measures, and an emergency response plan before exploration or production begins. These plans will need to be submitted to national authorities.

- Technical solutions presented by the operator need to be verified independently prior to and periodically after the installation is taken into operation.
- Companies will publish on their websites information about standards of performance of the industry and the activities of the national competent authorities. The confidentiality of whistle-blowers will be protected. Operators will be requested to submit reports of incidents overseas to enable key safety lessons to be studied.
- Companies will prepare emergency response plans based on their rig or platform risk assessments and keep resources at hand to be able to put them into operation when necessary. EU Member States will likewise take full account of these plans when they compile national emergency plans. The plans will be periodically tested by the industry and national authorities.
- Oil and gas companies will be fully liable for environmental damage caused to the protected marine species and natural habitats. For damage to waters, the geographical zone will be extended to cover all EU waters including the exclusive economic zone (about 370 km from the coast) and the continental shelf, where the coastal Member States exercise jurisdiction. For water damage, the present EU legal framework for environmental liability is restricted to territorial waters (about 22 km offshore).
- Offshore inspectors from Member States will work together to ensure effective sharing of best practices and contribute to developing and improving safety standards.
- The EU Commission will work with its international partners to promote the implementation of the highest safety standards across the world. Operators working in the EU will be expected to demonstrate they apply the same accident-prevention policies overseas as they apply in their EU operations.

Adoption of stricter regulation both at national and European or international level and the expected evolution in industrial practices would trigger cost increases to comply with new HSE standards. Eni exploration and development plans to produce hydrocarbons reserves and drilling programs could also be affected by changing HSE regulations and industrial practices. Lastly, the Company expects that production royalties and income taxes in the oil&gas industry will likely increase in future years.

Moreover, in order to achieve the highest safety standards of our operations in the Gulf of Mexico, Eni entered into a consortium led by Helix that worked at the containment of the oil spill at the Macondo well. The Helix Fast Response System performs certain activities associated with underwater containment of erupting wells, evacuation of hydrocarbon on the sea surface, storage and transport to the coastline.

As to major accidents, the Seveso III (Directive No. 2012/18/EU) was adopted on July 4, 2012 and entered into force on August 13, 2012. Member States have to transpose and implement the Directive by June 1, 2015.

The main changes in comparison to the previous Seveso Directive are:

- technical updates to take into account the changes in EU chemical classification, mainly regarding the 2008 European CLP Regulation of substances and mixtures;
- expanded public information about risks resulting from Company activities;
- modified rules in participation by the public in land-use planning projects related to Seveso plants; and
- stricter standards for inspections of Seveso establishments.

Eni is starting the initial activities aimed at guaranteeing the compliance of its own industrial sites.

HSE activity for the year 2013

Eni is committed to continuously improve its model for managing health, safety and environment issues across all its businesses in order to minimize risks associated with its industrial activities, ensure reliability of its industrial operations and comply with all applicable rules and regulations.

In 2013, Eni s business units continued to obtain certifications of their management systems, industrial installations and operating units according to the most stringent international standards. The total number of certifications achieved was 350 (340 in 2012), of which 112 certifications according to the ISO 14001 standard, 10 registrations according to the EMAS regulation (EMAS is the Environmental Management and Audit Scheme recognized by the European Union), 8 certifications according to the ISO 50001 standard (certification for an energy management system) and 109 according to the OHSAS 18001 standard (Occupational Health and Safety management Systems - requirements).

In 2013, Eni total HSE expenses (including cross-cutting issues such as HSE management systems implementation and certification, etc.) amounted to euro 1,423 million, down by 4.2% from 2012.

Environment. In 2013, Eni incurred total expenditures amounting to euro 711.5 million for the protection of the environment (with a reduction of 4.3% with respect to 2012). Current environmental expenses amounted to euro 468.1 million, in line with the 2012 figure, and mainly related to costs incurred with respect to remediation and reclamation activities, carried out mainly in Italy. Capitalized environmental expenditure decreased by 11.6% and mainly related to energy efficiency and climate change (particularly flaring down), air protection and spill prevention. Eni expects to continue incurring amount of capital environmental expenditures and current expenses in line with or above 2013 levels in future years.

Safety. Eni is committed to safeguard the safety of our employees and contractors as well as of all people living in the areas where our activities are conducted and our assets located. In 2013, the new legislation didn t have significant impact on the procedures already in place for safety in the workplace.

The improvement and dissemination of safety awareness through all levels of the Company s organization continued in 2013. This is one of the foundations of Eni s safety strategy, through a large communication campaign, launched in 2012, with the target of improving the conduct of employees/workers in the specific field of safety in the workplace. The campaign, will span over three years involving progressively the enterprise top management, the managers of operating sites and all the Eni s employees. Moreover, in 2013, Eni has continued its safety roadshow initiative, a series of meetings of the Company s top management with the industrial sites personnel (employees and contractors), dedicated to the sharing of the Company s safety targets and commitment, focusing also on the HSE aspects of the new process of qualification of vendors. In 2013, Eni has conceived an initiative aimed at issuing work permits in electronic form for standardizing and improving the related risk assessment process. The initiative will consist of implementing by 2014 the project on three pilot sites, with a gradual extension of the project to the other Eni sites in the course of the following years.

Results of efforts to achieve a better safety in all activities has brought an improvement of Eni workforce lost time injury frequency rate to 0.35 and of the severity rate to 0.014, decreasing by 28.7% and by 31.4% from 2012, respectively. The total recordable injury rate (1.04) decreased by 10.4% compared to 2012.

As to emergency preparedness, Eni has joint the Oil Spill Response Joint Industry Project (OSR-JIP) launched in December 2011 by International Association of Oil&Gas Producers (OGP) and International Petroleum Industry Environmental Conservation Association (IPIECA). This JIP will execute, over a three-year period, the outstanding recommendations from the report produced by the Global Industry Response Group (GIRG) set up after the Macondo accident. The existence of a JIP makes it easier for national administrations, intergovernmental organizations and willing third parties to participate in the studies and therefore to build their confidence in the results of the commissioned investigations and research. The OSR-JIP carries out specific projects dealing with exercise planning, in situ burning, dispersants advocacy-subsea, efficacy-post spill monitoring, upstream risk assessment and response capability, etc.

Costs incurred in 2013 to support the safety levels of operations and to comply with applicable rules and regulations were euro 408.8 million, up by 10.2% from 2012. Eni expects to continue incurring amounts of expenses for safety which will be in line with 2013 levels in future years.

Health. Eni s activities for protecting health aim at the continuous improvement of work conditions. We believe that we achieved a good performance in this area due to:

- plant and facility efficiency and reliability;
- promotion and dissemination of knowledge, adoption of best practices and operating management systems based on advanced criteria of protection of health and internal and external environment;
- certification programs of management systems for production sites and operating units;
- identified indicators in order to monitor exposure to chemical and physical agents;
- strong engagement in health protection for workers operating outside Italy also with the support of international health centers capable of guaranteeing a prompt and adequate response to any emergency;
- identification of an effective organization of health centers, in Italy and abroad; and
- training programs for medics and paramedics.

To protect the health and safety of its employees, Eni relies on a network of 413 health care centers located in its main operating areas. A set of international agreements with the best local and international health centers ensures efficient services and timely responses to emergencies.

Eni is engaged to the elaboration of HIA and relative standards to be applied to all new projects of evaluation of working exposure to environment, in Italy and abroad. The main aim of HIA is to avoid any negative impacts and maximize any positive impacts of the project on the host community and it is usually carried out as part of/or in conjunction with the Environmental and a Social Impact Assessment process. Its results are used to develop appropriate mitigation measures and an improvement plan with the host community.

In 2013, Eni incurred a total expense of euro 51.1 million, up by 6.1% from 2012, to protect the health of its employees. Eni expects to continue incurring amounts of expenses for health which will be in line or above with 2013 levels in future years.

Managing GHG emissions

In 2013, the II commitment period of the Kyoto Protocol started. The UN negotiations on Climate Change are going ahead in order to achieve a global agreement for the post 2020 regime at the 21st Conference of the Parties (COP21) that will be held in Paris in 2015. In this context the European Union has started a debate on the shaping of its Climate and Energy Policy in the long term (up to 2030). The debate shall be concluded by 2015 in order to present the outcomes at COP21 in Paris. As a major European energy company Eni is involved in the process.

To ensure comprehensive, transparent and accurate reporting for GHG emissions, Eni introduced in 2005 its own Protocol for accounting and reporting greenhouse gas emissions (GHG Accounting and Reporting Protocol), which is an essential requirement for emission certification. Indeed, accurate reporting supports the strategic management of risks and opportunities related to greenhouse gases, the definition of objectives and the assessment of progress. Eni GHG Protocol has been updated in 2012 to be in compliance with the new Monitoring and Reporting European Guideline (European Regulation No. 601/2012) and with the best practices reference document (American Petroleum Industry Compendium - August 2009). For safer and more accurate management of GHG emissions and with a view to support effective reporting, Eni provided all its business units with a dedicated database, in order to gather and report GHG emissions according to the Protocol and to ensure completeness, accuracy, transparency and consistency of GHG accounting as required by certification needs. In order to improve the Eni accounting and reporting process, in 2013 Eni provided independent verification of its 2012 equivalent CO_2 emissions data, as submitted to the Carbon Disclosure Project, and obtained the verification statement in accordance with ISO 14063-3.

Eni believes that in order to mitigate its impacts on climate change and reduce the risks related to climate regulations evolution it is important in the short term to diminish the carbon intensity of its operations and promote the use of low emission energy sources such as natural gas. Since a decade Eni has been identifying projects aimed at energy saving and emission reductions from its plants: in Africa many projects have been implemented in order to economically exploit gas associated with the production of liquids and reduce gas flaring.

Italy is subject to the European Union Emission Trading Scheme (EU-ETS) that was established by Directive No. 2003/87/EC. Effective from January 1, 2005, EU-ETS is the largest carbon market in the world for exchanging emission allowances targeting industrial installations with high carbon dioxide emissions. The EU-ETS Directive states that any operator, who produces GHG emissions in excess of the amounts allowed on the base of national allocation plan, is required to acquire allowances on the market to cover the excess emissions or to pay a penalty. The excess emissions penalty for the period 2013-2020 amounts to euro 100 for each tonne of carbon dioxide equivalent produced in excess of the allowances acquired on the market. The payment of the penalty shall not release the operator from the obligation to surrender an amount of allowances equal to those excess emissions when surrendering allowances in relation to the following calendar year. On January 1, 2013 the third phase (2013-2020) of EU-ETS has started. In this period the main instrument for allowances allocation is represented by sales auctioning and no more by the historical emissions. During this phase no more free allowances will be given to power plants (exception on few particular cases). Conversely, for all the other industrial sectors, the free allocation has been determined with the adoption of European benchmarks linked to the carbon intensity of each industrial process.

Currently Eni participates in the ETS scheme with 38 plants in Italy and 4 outside Italy, which collectively represent more than 40% of all GHG emissions generated by Eni s plants worldwide. In the period 2013-2020 Eni was entitled to allowances equal to 69 mmtonnes of carbon dioxide. Due to stricter allocation rules in the third phase (2013-2020) of the Emissions Trading Scheme, Eni is been receiving a lower amount of free allowances in comparison with the second phase (2008-2012). As a consequence, in the next four-year period (2014-2017), Eni shall buy on the market an amount of allowances to cover GHG emissions of its industrial plants. The majority of the deficit (about 80%) is concentrated in the power sector.

Regulation of Eni s businesses

Overview

The matters regarding the effects of recent or proposed changes in Italian legislation and regulations or EU directives discussed below and elsewhere herein are forward-looking statements and involve risks and uncertainties that could cause the actual results to differ materially from those in such forward-looking statements. Such risks and uncertainties include the precise manner of the interpretation or implementation of such legal and regulatory changes or proposals, which may be affected by political and other developments.

Regulation of exploration and production activities

Eni s exploration and production activities are conducted in many countries and are therefore subject to a broad range of legislation and regulations. These cover virtually all aspects of exploration and production activities, including matters such as license acquisition, production rates, royalties, pricing, environmental protection, export, taxes and foreign exchange. The terms and conditions of the leases, licenses and contracts under which these oil and gas interests are held vary from country to country. These leases, licenses and contracts are generally granted by or entered into with a government entity or state company and are sometimes entered into with private property owners. These arrangements usually take the form of licenses or production sharing agreements. See "Regulation of the Italian hydrocarbons industry" and "Environmental matters" for a description of the specific aspects of the Italian regulation and of environmental regulation concerning Eni s exploration and production activities. Licenses (or concessions) give the holder the right to explore for and exploit a commercial discovery. Under a license, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the license holder is entitled to all production minus any royalties that are payable in-kind. A license holder is generally required to pay production taxes or royalties, which may be in cash or in-kind. Both exploration and production licenses are generally for a specified period of time (except for production licenses in the United States which remain in effect until production ceases). The term of Eni s licenses and the extent to which these licenses may be renewed vary by area. In production sharing agreements, entitlements to production volumes are defined on the basis of contractual agreements drawn up with state oil companies which hold the concessions. Such contractual agreements regulate the recovery of costs incurred for the exploration, development and operating activities (cost oil) and give entitlement to a portion of the production volumes exceeding volumes destined to cover costs incurred (profit oil). A similar scheme to PSA applies to Service and "Buy-Back" contracts. In general, Eni is required to pay income tax on income generated from production activities (whether under a license or PSA). The taxes imposed upon oil and gas production profits and activities may be substantially higher than those imposed on other businesses.

Regulation of the Italian hydrocarbons industry

The matters regarding the effects of recent or proposed changes in Italian legislation and regulations or EU directives discussed below and elsewhere herein are forward-looking statements and involve risks and uncertainties that could cause the actual results to differ materially from those in such forward-looking statements. Such risks and uncertainties include the precise manner of the interpretation or implementation of such legal and regulatory changes or proposals, which may be affected by political and other developments.

Exploration & Production

The Italian hydrocarbons industry is regulated by a combination of constitutional provisions, statutes, governmental decrees and other regulations that have been enacted and modified from time to time, including legislation enacted to implement EU requirements (collectively, the "Hydrocarbons Laws").

Exploration permits and production concessions. Pursuant to the Hydrocarbons Laws, all hydrocarbons existing in their natural condition in strata in Italy or beneath its territorial waters (including its continental shelf) are the property of the State. Exploration activities require an exploration permit, while production activities require an exploiting concession, in each case granted by the Minister of Economic Development through exploration permits. The initial duration of an exploration permit is six years, with the possibility of obtaining two three-year extensions and an additional one-year extension to complete activities underway. Upon each of the three-year extensions, 25% of the area under exploration must be relinquished to the State (only for initial acreages larger than 300 square kilometers). The initial duration of a production concession is 20 years, with the possibility of obtaining a ten-year extension and additional five-year extensions until the field depletes.

Royalties. The Hydrocarbons Laws require the payment of royalties for hydrocarbon production. As per Legislative Decree No. 625 of November 25, 1996, subsequent modifications and integrations and Law Decree No. 83 of June 22, 2012, royalties are equal to 10% for gas and oil productions onshore, to 10% for gas and 7% for oil offshore, with fixed amount of exemption. Only in the Autonomous Region of Sicily, following the Regional Law No. 9 of May 15, 2013, royalties are equal to 20% for oil and gas, with no exemptions).

Gas & Power

Natural gas market in Italy

Legislative Decree No. 130 of August 13, 2010 containing measures for increasing competition in the natural gas market and transferring the ensuing benefits to final customers according to Article 30, lines 6 and 7, of Law No. 99 of July 23, 2009

In 2011, Legislative Decree No. 130 of August 13, 2010 titled "New measures to improve competitiveness in the natural gas market and to ensure the transfer of economic benefits to final customers" became effective. This new regulation replaced the previous system of gas antitrust thresholds defined by Legislative Decree No. 164 of May 23, 2000 by introducing a 40% ceiling to the wholesale market share of each Italian gas operator who inputs gas into the Italian backbone network. In the frame of Legislative Decree No. 130/2010 Eni has committed itself to build new storage capacity for 4 BCM within five years from the enactment of the Decree; as a consequence the cap provided by the Legislative Decree No. 130/2010 to its market share in Italy rises from 40% to 55%. In the case of violations of the mandatory threshold, Eni is obliged to execute gas release measures at regulated prices up to 4 BCM over a two-year period following the ascertainment of the breach. Access to the new storage capacity is reserved to industrial customers and their consortium (3 BCM, already allocated) and to gas-fired power plants (1 BCM). Furthermore, the Decree establishes that upon request, industrial customers are granted, for the new storage capacity which is not yet available:

- from April 2012 a "virtual storage service", which consists of the possibility to deliver gas during the summer to a "virtual storage operator" at an European hub TTF, Zeebrugge or PSV and to collect equivalent gas quantities during the winter at the Italian PSV, paying for the service a fee equivalent to the cost of storage plus transmission costs, if any. Therefore, industrial operators benefit from the price differentials due to the seasonal swings of gas demand.

Law Decree of December 23, 2013 converted to Law on February 21, 2014 allows industrial operators to renounce definitively to the conferred storage capacity under construction and provides electricity producers an option for further allotment of storage capacity within April/May 2014. Eni will be only obliged to build the storage capacity which corresponds to the quantities confirmed or requested under the above mentioned provisions. This obligation should not include additional costs for the natural gas system.

By January 2014 and for a three-year period, the Decree also establishes that any operator running natural gas in the transportation network and with a wholesale market share higher than 10% is obliged to offer, on the natural gas future market managed by an Italian independent authority, a volume of natural gas corresponding to 5% of the annual imported volumes. The obligation should be combined contextually by a buy request, on the same market, of the same quantity of gas offered and with a spread between bid and ask prices lower than an amount to be defined by the Minister of Economic Development, based on a proposal of the Italian Regulator AEEG. This body also defines the modes for the fulfillment of the above mentioned obligation.

Eni s management is monitoring this issue with a view of assessing any possible financial or economic impact associated with the enacted measures and their evolution. Management also believes that this new gas regulation will increase competition in the wholesale natural gas market in Italy leading to further margin pressures.

Law Decree No. 1 of January 24, 2012 for new liberalization measures in Italy

Law Decree No. 1 enacted by the Italian Government on January 24, 2012, the so-called Liberalization Decree was converted to Law No. 20 on March 24, 2012.

This Law aimed to:

enhance competitiveness in gas tariffs to residential customers and in the distribution of refined products. The AEEG, in charge with setting pricing mechanisms for supplies to users starting from the second quarter of 2012, updated the indexation mechanism by increasing the weight of spot prices in the indexation of the supply costs of gas. In particular, spot prices have represented a share of 3% and 4% of the cost of gas in the second and third quarter 2012, respectively, and 5% in the period October 2012-March 2013, with the remaining part indexed to the supply cost provided by a panel of oil-linked long-term contracts;

reduce the cost of natural gas for industrial customers by giving them direct access to storage capacity. This will be possible with a redefinition of the binding modulation for residential customers in case of rigid winter conditions and by freeing up a percentage of strategic storage volumes. For this purpose, the Ministry of Economic Development enacted a Law Decree on February 15, 2013, introducing changes to the criteria of assignment of storage capacity in application of Article 14 of Law Decree No. 1, 2012 setting forth that:

- the storage capacity that would be available as a result of new mechanisms for determining the volumes of strategic storage, as well as new modalities of calculation of obligation limitations based on the criteria issued by the Ministry of the Economic Development, are assigned, for a space determined by the Ministry itself, for the offer to industrial sector, integrated transportation services through International pipelines and re-gasification, including natural gas storage, allowing the supplies of natural gas from

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abroad, in accordance with security criteria requested, as well as by re-gasification companies, as a guaranty for the respect of re-gasification programs of their customers when non predictable events occur; and

- is determined part of the space of modulation storage devoted to the needs of "vulnerable events", to be assigned, for the needs of the clients themselves, with procedure of competitive bid, and the part of the same space of storage modulation to be assigned with ongoing allocation procedures.

Based on the principles described above, at the beginning of 2013, the Minister of Economic Development and the Italian Authority for Electricity and Gas introduced new criteria for the allocation of gas storage capacities for the thermal year 2013-2014. In particular, the Decree on gas storage capacity allocation rules that, from the period April 1, 2013 to March 31, 2014, 4.2 BCM of storage is to be allocated through auction, of which 2.5 BCM is reserved to domestic users and 1.7 BCM for other users, including those without domestic consumers in their portfolios. A further 4.2 BCM of storage capacity reserved to domestic users would still be allocated through the current system, which assigns pro-rata storage volumes to operators based on the size of the market they cover.

Negotiation platform for gas trading

In compliance with the provisions of Law No. 99 of July 23, 2009, on March 18, 2010, the Ministry of Economic Development published a Decree that implements a trading platform for natural gas from May 10, 2010 aimed at increasing competition and flexibility on wholesale markets. Management and organization of this platform are entrusted to an independent operator, the Gestore dei Mercati Energetici (GME), an Italian agency. On this platform are traded also volumes of gas corresponding to the legal obligations on part of Italian importers and producers as per Law Decree No. 7/2007. Under these provisions, importers were expected to supply given amounts of gas (from 5% to 10% of total gas import) to the virtual exchange in order to receive permission to import, as well as volumes corresponding to royalties due by owners of mineral rights to the Italian State (and to Basilicata and Calabria Regions). Eni has complied with those requirements by supplying the set volumes of its imported natural gas in each thermal year following the law enactment. Operators, including non-importers, are allowed to trade additional gas volumes over the compulsory amounts on the platform according to the supply rules determined by the AEEG. Since December 2010, the GME is also trader s counterparty in transactions on the spot market for natural gas (divided into day-ahead market and intraday market). We believe that these measures have increased the level of liquidity in the Italian spot market of gas.

Natural gas prices

Following the liberalization of the natural gas sector introduced in 2000 by Decree No. 164, prices of natural gas in the wholesale market which includes industrial and power generation customers are freely negotiated. However the AEEG holds a power of surveillance on this matter (see below) under Law No. 481/1995 (establishing the AEEG) and Legislative Decree No. 164/2000. Furthermore, the AEEG has been entrusted by the Presidential Decree dated October 31, 2002 with the power of regulating natural gas prices to residential and commercial customers, also with a view of containing inflationary pressure deriving from increasing energy costs. Consistently with those provisions, companies which engage in selling natural gas through local networks are currently required to offer to those customers the regulated tariffs set by AEEG beside their own price proposals.

An important regulatory development has occurred in the first half of 2013. This relates to the implementation of a new tariff regime for Italian residential clients who are entitled to be safeguarded in accordance with current regulations. Clients who are eligible to the tariff mechanism set by the AEEG are residential clients who did not opt for choosing a supplier at the opening of the market (including those who consume less than 200,000 CM/y and residential buildings) and also include all customers consuming less than 50,000 CM/y and certain public services (for example hospitals and other social security facilities). With resolution No. 196 effective from October 1, 2013, the AEEG reformulated the pricing mechanism of gas supplies to those customers by providing a full indexation of the raw material cost component of the tariff to spot prices versus the previous regime that provided a mix between an oil-based indexation and spot prices. The new tariff regime intends to partially offset the negative impact to be born by wholesalers by introducing a pricing component intended to cover the risks and costs of the supplies to wholesalers. Furthermore, it has been provided a stability mechanism whereby a wholesaler part of a long-term, take-or-pay gas supply contract may opt for being reimbursed of the negative difference between the oil-linked costs of gas supplies and spot prices in the next two thermal years following the new regime implementation. Conversely, in case spot prices fall below the oil-linked cost of gas supplies in the following two thermal years, the same wholesaler is obliged to refund customers of the difference. This stability mechanism needs a further regulatory act to be implemented by the AEEG. The new tariff regime has substantially reduced the tariff components intended to cover storage and transportation costs. Finally, it also introduced a pricing component intended to remunerate certain marketing costs incurred by retail operators, including administrative and retention costs, losses incurred due to customer default and a return on capital employed.

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Similarly other regulatory authorities in European countries where Eni is present are planning to issue a regulation aimed at introducing a hub component in the pricing formulas related to retail clients as well as measures to boost liquidity and competitiveness in the gas market.

Refining and marketing of petroleum products

Refining. The regulations introduced with Law No. 9/1991 and No. 239/2004 (Article 1, paragraphs 56, 57 and 58) significantly changed the norms introduced in the 1930 s that required that any refining activity be handled under a concession from the State. Today an authorization is required to set up new processing and storage plants and for any change in the capacity of mineral processing plants, while all other changes that do not affect capacity can be freely implemented. Another simplification measure has been introduced by Law Decree No. 5/2012 that defined mineral oil processing and storage plants as "strategic settlements" that need authorization from the State, in agreement with the relevant Region, and imposes a single process of authorization that must be closed within 180 days. Management expects no material delays in obtaining relevant concessions for the upgrading of the Sannazzaro and Taranto refineries as planned in the medium term.

Marketing. Following the enactment of the above mentioned Law Decree No. 1 of January 24, 2012, certain measures are expected to be introduced in order to increase levels of competition in the retail marketing of fuels. The rules regulating relations between oil companies and managers of service stations have been changed introducing the difference between principal and non-principal of a service station. Starting from June 30, 2012 principals will be allowed to supply freely up to 50% of their requirements. In such case the distributing company will have the option to renegotiate terms and conditions of supplies and brand name use. As for non-principals, the law allows the parties to renegotiate terms and conditions at the expiration of existing contracts and new contractual forms can be introduced in addition to the only one allowed so far, i.e. exclusive supply. The law also provides for an expansion of non-oil sales. Eni expects developments on this issue to further increase pressure on selling margins in the retail marketing of fuels and to reduce opportunities of increasing Eni s market share in Italy.

Service stations. Legislative Decree No. 32 of February 11, 1998, as amended by Legislative Decree No. 346 of September 8, 1999 and Law Decree No. 383 of October 29, 1999, as converted in Law No. 496 of December 28, 1999, significantly changed Italian regulation of service stations. Legislative Decree No. 32 replaces the system of concessions granted by the Ministry of Industry, regional and local authorities with an authorization granted by City authorities while the Legislative Decree No. 112 of March 31, 1998 still confirms the system of such concessions for the construction and operation of service stations on highways and confers the power to grant to Regions.

From 2000 onwards, a number of administrative measures have been enacted in Italy with the goal of modernizing and making more efficient the Italian network. A Ministerial Decree of October 31, 2001 established the criteria for the closing down of incompatible stations, the renewal of the network, the opening up of new stations and the regulations of the operations of service stations on matters such as automation, working hours and non-oil activities. Law Decree No. 98/2011 converted into Law No. 111/2011, contains new guidelines for improving market efficiency and service quality and increasing competition. Among other things it provides that within July 6, 2012 all service stations must be provided with self-service equipment and that Regions will update their regulations in order to allow the sale of non-oil products in all service stations. Law Decree No. 1/2012 also allowed the installation of fully-automated service stations with prepayment, but only outside City areas. Law No. 133 of August 6, 2008, by intervening in competition provisions, removes some national and regional regulations which might prejudice the liberty of establishment and introduces new provisions particularly concerning the elimination of restrictions concerning distances between service stations, the obligation to undertake non-oil activities and the liberalization of opening hours. Management believes that those measures have supported competition in the Italian retail market.

Petroleum product prices. Petroleum product prices were completely deregulated in May 1994 and are now freely established by operators. Oil and gas companies periodically report their recommended prices to the Ministry of Productive Activities; such recommendations are considered by service station operators in establishing retail prices for petroleum products.

Compulsory stocks. According to Legislative Decree of December 31, 2012, No. 249 enacting Directive No. 2009/119/EC (which regulates the obligation of Member States to keep a minimum amount of stocks of crude oil and/or petroleum products) compulsory stocks, must be at least equal to the quantities required by 90 days of consumption of net import, including 10% deduction for minimum operational requirements. Decree No. 249/2012 states that compulsory stocks are determined each year by a decree of the Minister of Economic Development based on domestic consumption data of the previous year, defining also the amounts to be held by each oil company.

The Legislative Decree No. 249/2012 sets forth in particular: (a) that a high level of oil security of supply through a reliable mechanism to assure the physical access to oil emergency and specific stocks shall be kept; and (b) the institution of a Central Stockholding Entity under the control of the Ministry of Economic Development that should be in charge of: (i) the purchase, holding, sell and transportation of specific stocks of products; (ii) the stocktaking; (iii) the statistics on emergency, specific and commercial stocks; and, eventually (iv) the storage and transportation service of emergency and commercial stocks in favor of sellers of petroleum products not vertically integrated in the oil chain.

As of December 31, 2013, Eni owned 6.3 mmtonnes of oil products inventories, of which 4.7 mmtonnes as compulsory stocks , 1.4 mmtonnes related to operating inventories in refineries and deposits (including 0.2 mmtonnes of oil products contained in facilities and pipelines) and 0.2 mmtonnes related to specialty products. Eni s compulsory feedstock (23%), fuel oil (6%) and other products (4%) and they were located throughout the Italian territory both in refineries (74%) and in storage sites (26%).

Competition

Like all Italian companies, Eni is subject to Italian and EU competition rules. EU competition rules are set forth in Articles 101 and 102 of the Lisbon Treaty on the Functioning of the European Union entered into force on December 1, 2009 ("Article 101" and "Article 102", respectively being the result of the new denomination of former Articles 81 and 82 of the Treaty of Rome as amended by the Treaty of Amsterdam dated October 2, 1997 and entered into force on May 1, 1999) and EU Merger Control Regulation No. 139 of 2004 (EU Regulation 139). Article 101 prohibits collusion among competitors that may affect trade among Member States and that has the object or effect of restricting competition within the EU. Article 102 prohibits any abuse of a dominant position within a substantial part of the EU that may affect trade among Member States. EU Regulation 139 sets certain turnover limits for cross-border transactions, above which enforcement authority rests with the European Commission and below which enforcement is carried out by national competition authorities, such as the Antitrust Authority in the case of Italy. On May 1, 2004, a new regulation of the European Council came into force (No. 1/2003) which substitutes Regulation No. 17/1962 on the implementation of the rules on competition laid down in Articles 101 and 102 of the Treaty. In order to simplify the procedures required of undertakings in case of conducts that potentially fall within the scope of Article 101 and 102 of the Treaty, the new regulation substitutes the obligation to inform the Commission with a self assessment by the undertakings that such conducts does not infringe the Treaty. In addition, the burden of proving an infringement of Article 101(1) or of Article 102 of the Treaty shall rest on the party or the authority alleging the infringement. The undertaking or association of undertakings claiming the benefit of Article 101(3) of the Treaty shall bear the burden of proving that the conditions of that paragraph are fulfilled. The regulation defines the functions of authorities guaranteeing competition in Member States and the powers of the Commission and of national courts. The competition Authorities of the Member States shall have the power to apply Articles 101 and 102 of the Treaty in individual cases. For this purpose, acting on their own initiative or on a complaint, they may take the following decisions:

- requiring that an infringement be brought to an end;
- ordering interim measures;
- accepting commitments; and
- imposing fines, periodic penalty payments or any other penalty provided for in their national law.

National courts shall have the power to apply Articles 101 and 102 of the Treaty. Where the Commission, acting on a complaint or on its own initiative, finds that there is an infringement of Article 101 or of Article 102 of the Treaty, it may: (i) require the undertakings and associations of undertakings concerned to bring such infringement to an end; (ii) order interim measures; (iii) make commitments offered by undertakings to meet the concerns expressed to them by the Commission binding on the undertakings; and (iv) find that Articles 101 and 102 of the Treaty are not applicable to an agreement for reasons of Community public interest. Eni is also subject to the competition rules established by the Agreement on the European Economic Area (the "EEA Agreement"), which are analogous to the competition rules of the Lisbon Treaty (ex Treaty of Rome) and apply to competition in the European Economic Area (which consists of the EU and Norway, Iceland and Liechtenstein). These competition rules are enforced by the European Commission and the European Free Trade Area Surveillance Authority. In addition, Eni s activities are subject to Law No. 287 of October 10, 1990 (the "Italian Antitrust Law"). In accordance with the EU competition rules, the Italian Antitrust Law prohibits collusion among competitors that restricts competition within Italy and prohibits any abuse of a dominant position within the Italian market or a significant part thereof. However, the Italian Antitrust Authority may exempt for a limited period agreements among companies that otherwise would be prohibited by the Italian Antitrust Law if such agreements have the effect of improving market conditions and ultimately result in a benefit for consumers.

Property, plant and equipment

Eni has freehold and leasehold interests in real estate in numerous countries throughout the world. Management believes that certain individual petroleum properties are of major significance to Eni as a whole. Management regards an individual petroleum property as material to the Group in case it contains 10% or more of the Company worldwide proved oil and gas reserves and management is committed to invest material amounts of expenditures in developing it in the future. See "Exploration & Production" above for a description of Eni s both material and other properties and reserves and sources of crude oil and natural gas.

Organizational structure

Eni SpA is the parent company of the Eni Group. As of December 31, 2013, there were 252 fully-consolidated subsidiaries and 148 associates, joint ventures and joint operations that were accounted for under the equity or cost method or in accordance to Eni s share of revenues, costs and assets of the joint operations calculated based on Eni s working interest. For a list of subsidiaries of the Company, see Exhibit 8. List of Eni s fully-consolidated subsidiaries for year 2013 .

Item 4A. UNRESOLVED STAFF COMMENTS

None.

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Item 5. OPERATING AND FINANCIAL REVIEW AND PROSPECTS

This section is the Company s analysis of its financial performance and of significant trends that may affect its future performance. It should be read in conjunction with the Key Information presented in Item 3 and the Consolidated Financial Statements and related Notes thereto included in Item 18. The Consolidated Financial Statements are prepared in accordance with International Financial Reporting Standards as issued by the IASB.

This section contains forward-looking statements which are subject to risks and uncertainties. For a list of important factors that could cause actual results to differ materially from those expressed in the forward-looking statements, see the cautionary statement concerning forward-looking statements on page ii.

Executive summary

Eni reported net profit from continuing operations (net of minority interest) of euro 5,160 million for the year ended December 31, 2013, representing an increase of 22.9% from 2012. That amount represented net profit from continuing operations attributable to Eni s shareholders. The increase was driven by large gains recorded on the divestment of certain assets, which more than offset a significant reduction in the underlying performance recorded by all of Eni s business segments.

The Group s operating profit from continuing operations for the year ended December 31, 2013, amounted to euro 8,888 million, down 41.6% from 2012. All of Eni s business segments reported lower results. The Exploration & Production segment was impacted by extraordinary disruptions to its producing activities related to geopolitical factors mainly in Libya and Nigeria as well as the appreciation of the euro against the U.S. dollar, with an overall reduction in operating profit of euro 3,602 million, down by 19.5% from 2012. The Gas & Power, Refining & Marketing and the Chemical businesses were hit by a continued deterioration in selling prices and margins due to the economic downturn and structural headwinds in the trading environment reflecting plunging demand for energy commodities, excess supplies/overcapacity and competitive pressure. Finally Saipem reported sharply lower operating results due to large losses on contracts. Additionally, the reduced profitability outlook in those businesses led management to recognize significant amounts of asset impairments in the region of euro 2.4 billion to align the book values of goodwill and other intangible assets in the gas business, electricity generation plants and refineries to their lower values-in-use. However, asset impairments were lower than the approximately euro 4 billion amount that was recorded in 2012.

Eni s lowered operating profit was partly offset by the recognition of gains in the range of euro 6 billion which were recorded with respect to the sale of Eni s 28.57% interest in Eni East Africa, which is the operator of Area 4 in Mozambique, to China National Petroleum Corp (euro 3,359 million) and Eni s interest in Artic Russia (euro 1,682 million) which was classified as an asset held for sale and measured at fair value, after joint control was lost over the investee following the satisfaction, before year end, of all conditions precedent to the Sale and Purchase Agreement signed with certain Gazprom companies in November 2013. The consideration for the disposal was received in January 2014. In 2012, Eni recorded investment gains in the range of euro 2 billion relating to its Galp shareholding reflecting the divestment of part of Eni s interest in the investee, the revaluation at fair market value of the residual stake and other transactions.

Finally, income taxes decreased by euro 2,674 million driven by lower taxes currently payable recorded by the Exploration & Production segment reflecting lower taxable profit.

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The table below sets forth for the reported periods details of certain, identified gains and charges included in net profit attributable to Eni s shareholders from continuing operations. These gains and charges mainly related to asset impairments, risk and other provisions, write downs of deferred tax assets, capital and revaluation gains on investments and other tangible assets, as well as inventory holding gains or losses.

Eni Group	Year ended December 31,		
	2011	2012	2013
	(euro million)		
Profit (loss) on stock	1,113	17	(716)
Environmental provisions	(176)	(63)	(205)
Impairment losses	(1,031)	(3,978)	(2,400)
Net gains on disposal of assets	57	548	187
Risk provisions	(88)	(945)	(334)
Provision for redundancy incentives	(203)	(64)	(270)
Fair value gains/losses on commodity derivatives	(15)	1	(315)
Other charges/gains net	(169)	(271)	96
Net (charges) gains in operating profit	**(512)**	**(4,755)**	**(3,957)**
Capital and revaluation gains related to Galp		2,011	98
Capital gain on the sale of 28.57% of Eni East Africa			3,359
Fair-value revaluation of Artic Russia			1,682
Other capital gains/write downs on investments	879	(108)	
Write downs of deferred tax assets/recognition of deferred tax liabilities	(552)	(803)	(1,444)
Tax effects on the above listed items	151	848	888
Other	(2)	(123)	101
Net (charges) gains in net profit	**(36)**	**(2,930)**	**727**

In evaluating the Company s underlying performance, management also considers a measure of profits that excludes the above listed gains and charges. On that basis, 2013 net profit would have decreased by euro 727 million and the comparative 2012 result would have improved by euro 2,930 million and as such 2013 performance would have been worse than the previous year by 37.8%.

Net cash provided by operating activities from continuing operations amounted to euro 11,026 million for the year ended December 31, 2013 and proceeds from divestments amounted to euro 6,360 million. Those cash inflows funded cash outflows relating to capital expenditures totaling euro 12,800 million and investments (euro 317 million), as well as dividend payments amounting to euro 4,199 million (of which euro 1,993 million relating to the 2013 interim dividend, euro 1,956 million to the balance of the dividend for fiscal year 2012 to Eni s shareholders and the remaining part related to other dividend payments mainly relating Saipem).

Disposals of assets primarily related to the divestment of a 28.57% interest in Eni East Africa for euro 3,386 million, the sale of an 11.69% interest in Snam to institutional investors (euro 1,459 million) and of an 8.19% interest in Galp for euro 830 million.

As of December 31, 2013, net borrowings amounted to euro 14,963 million, a decrease of euro 106 million from December 31, 2012.

In 2013, oil and natural gas production available for sale averaged 1,537 KBOE/d, down by 5.8% from 2012. The decline was mainly caused by the extraordinary disruptions which impacted production performance in Libya, Nigeria and Algeria.

Worldwide gas sales in 2013 amounted to 93.17 BCM, a decrease of 2.15 BCM from 2012, or 2.3%, reflecting an ongoing demand downturn, competitive pressure and oversupply. Natural gas sales in Italy increased by 1.08 BCM from 2012, while lower volumes were recorded in a number of European markets (down by 5.61 BCM, or 11.6%) such as Benelux, the Iberian Peninsula and the United Kingdom. Sales increased in Germany-Austria, and in the LNG business in overseas markets.

In 2013, capital expenditures of continuing operations amounted to euro 12,800 million (euro 12,805 million in 2012) and mainly related to:

- oil and gas development activities (euro 8,580 million) deployed mainly in Norway, the United States, Angola, Congo, Italy, Nigeria, Kazakhstan, Egypt and the United Kingdom;
- exploration projects (euro 1,669 million) of which 98% was spent outside Italy, primarily in Mozambique, Norway, Congo, Togo, Nigeria, the United States and Angola;

upgrading the fleet used in the Engineering & Construction segment (euro 902 million); and

refining, supply and logistics in Italy and outside Italy (euro 462 million) with projects designed to improve the conversion rate and flexibility of refineries, in particular at the Sannazzaro refinery, as well as the upgrade of the refined product retail network in Italy and in the rest of Europe (euro 210 million).

During the 2014-2017 four-year period, Eni expects to invest approximately euro 54 billion in capital expenditures and exploration projects to implement its growth strategy, based on the assumptions discussed below under "Management s expectation of operations".

Trading environment

	2011	2012	2013
Average price of Brent dated crude oil in U.S. dollars (1)	111.27	111.58	108.66
Average price of Brent dated crude oil in euro (2)	79.94	86.83	81.82
Average EUR/USD exchange rate (3)	1.392	1.285	1.328
Average European refining margin in U.S. dollars (4)	2.06	4.83	2.64
Euribor - three month euro rate % (3)	1.4	0.6	0.2

(1) Price per barrel. Source: Platt s Oilgram.

(2) Price per barrel. Source: Eni s calculations based on Platt s Oilgram data for Brent prices and the EUR/USD exchange rate reported by the European Central Bank (ECB).

(3) Source: ECB.

(4) Price per barrel. FOB Mediterranean Brent dated crude oil. Source: Eni calculations based on Platt s Oilgram data.

When the term margin is used in the following discussion, it refers to the difference between the average selling price and reflect the trading environment and are, to a certain extent, a gauge of industry profitability.

Eni s results of operations and the year-to-year comparability of its financial results are affected by a number of external factors which exist in the industry environment, including changes in oil, natural gas and refined products prices, industry-wide movements in refining and petrochemical margins and fluctuations in exchange rates and interest rates. Changes in weather conditions from year to year can influence demand for natural gas and some petroleum products, thus affecting results of operations of the natural gas business and, to a lesser extent, of the refining and marketing business. See "Item 3 Risk factors".

In 2013, Eni s results were achieved in a trading environment characterized by lower oil and gas realizations in dollar terms due to a slightly declining Brent price, down by 2.6% from 2012. Refining margins in the Mediterranean area fell to unprecedented levels, down to less than one dollar per barrel (down by 45.3% from 2012) due to structural headwinds in the industry driven by overcapacity, lower demand and increasing competition from imported refined product streams. Furthermore, Eni s results in the Refining & Marketing Division were affected by narrowing differentials between the heavy crudes processed by Eni s refineries and the marker Brent which reflected the lower availability of the former in the Mediterranean Area. The European gas market was characterized by a weak demand, strong competitive pressures and oversupplies. Price competition among operators has been stiff exacerbated by minimum take obligations provided by long-term purchase contracts of gas and reduced sale opportunities. Spot prices in Europe recovered somewhat from the depressed levels recorded in 2012 and increased by 12.2% year on year; however this was not reflected in gas margins because of higher oil-linked supply costs. Instead, spot prices recorded in Italy fell sharply as they fully aligned to spot prices at continental hubs also eroding a positive differential held in previous years due to logistic disadvantages. This trend drove down Eni s realizations on gas sales in Italy which were sharply lower due to a rapid shift in the indexation of selling prices to spot benchmarks in short term contracts. The decline in spot prices was also transferred to the Company long-term sale contracts. Eni s results were also impacted by sharply lower margins in the production and sale of electricity due to oversupply and increasing competition from more competitive sources. Results of 2013 were affected by the appreciation of the euro against the dollar (up by 3.3% over the year).

Key consolidated financial data

		2011	2012	2013
			(euro million)	
Net sales from operations from continuing operations		107,690	127,109	114,697
Operating profit from continuing operations		16,803	15,208	8,888
Net profit attributable to Eni from continuing operations		6,902	4,200	5,160
Net profit attributable to Eni from discontinued operations		(42)	3,590	
Net profit attributable to Eni		6,860	7,790	5,160
Net cash provided by operating activities - continuing operations		13,763	12,552	11,026
Capital expenditures - continuing operations		11,909	12,805	12,800
Acquisitions of investments and businesses		360	569	317
Shareholders equity including non-controlling interest at year end		60,393	62,417	61,049
Net borrowings at year end		28,032	15,069	14,963
Net profit attributable to Eni basic and diluted from continuing operations	(euro per share)	1.90	1.16	1.42
Net profit attributable to Eni basic and diluted from discontinued operations		(0.01)	0.99	
Net profit attributable to Eni basic and diluted		1.89	2.15	1.42
Dividend per share	(euro per share)	1.04	1.08	1.10
Ratio of net borrowings to total shareholders equity including non-controlling interest (leverage) (1)		0.46	0.24	0.25

(1) For a discussion of the usefulness of and a reconciliation of these non-GAAP financial measures with the most directly comparable GAAP financial measures see "Liquidity and capital resources Financial conditions" below.

Critical accounting estimates

The preparation of the Consolidated Financial Statements requires the use of estimates and assumptions that affect the assets, liabilities, revenues and expenses reported in the financial statements, as well as amounts included in the notes thereto, including discussion and disclosure of contingent liabilities. Estimates made are based on complex or subjective judgments and past experience of other assumptions deemed reasonable in consideration of the information available at the time. The accounting policies and areas that require the most significant judgments and estimates to be used in the preparation of the Consolidated Financial Statements are in relation to the accounting for oil and natural gas activities, specifically in the determination of proved and proved developed reserves, impairment of fixed assets, intangible assets and goodwill, asset retirement obligations, business combinations, pensions and other post-retirement benefits, recognition of environmental liabilities and recognition of revenues in the oilfield services construction and engineering businesses. Although the Company uses its best estimates and judgments, actual results could differ from the estimates and assumptions used. A summary of significant estimates follows.

Oil and gas activities

Engineering estimates of the Company s oil and gas reserves are inherently uncertain. Proved reserves are the estimated volumes of crude oil, natural gas and gas condensates, liquids and associated substances which geological and engineering data demonstrate that can be economically producible with reasonable certainty from known reservoirs under existing economic conditions and operating methods. Although there are authoritative guidelines regarding the engineering and geological criteria that must be met before estimated oil and gas reserves can be designated as "proved", the accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Field reserves will only be categorized as proved when all the criteria for attribution of proved status have been met. At this stage, all booked reserves are classified as proved undeveloped. Volumes are subsequently reclassified from proved undeveloped to proved developed as a consequence of development activity. The first proved developed bookings occur at the point of first oil or gas production. Major development projects typically take one to four years from the time of initial booking to the start of production. Eni reassesses its estimate of proved reserves periodically. The estimated proved reserves of oil and natural gas may be subject to future revision and upward and downward revision may be made to the initial booking of reserves due to production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity. In particular, changes in oil and natural gas prices could impact the amount of Eni s proved reserves in regards to the initial estimate and, in the case of production sharing agreements and buy-back contracts, the share of production and reserves to which Eni is entitled. Accordingly, the estimated reserves could be materially different from the quantities of oil and natural as that ultimately will be recovered. Oil and natural gas reserves have a direct impact on certain amounts reported in the

Consolidated Financial Statements. Estimated proved reserves are used in determining depreciation and depletion expenses and impairment expense. Depreciation and depletion rates on oil and gas assets using the UOP basis are determined from the ratio between the amount of hydrocarbons extracted in the quarter and proved developed reserves existing at the end of the quarter increased by the amounts extracted during the quarter. Assuming all other variables are held constant, an increase in estimated proved developed reserves for each field decreases depreciation and depletion expense. Conversely, a decrease in estimated proved developed reserves increases depreciation and depletion expense. In addition, estimated proved reserves are used to calculate future cash flows from oil and gas properties, which are used to assess any impairment loss. The larger is the volume of estimated reserves, the lower is the likelihood of asset impairment.

Impairment of assets

Assets are impaired when there are events or changes in circumstances that indicate the carrying values of the assets are not recoverable. Such impairment indicators include changes in the Group s business plans, changes in commodity prices leading to unprofitable performance, a reduced utilization of the plants and, for oil and gas properties, significant downward revisions of estimated proved reserve quantities or significant increase of the estimated development costs. Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain and complex matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses, production profiles and the outlook for global or regional market supply and demand conditions for crude oil, natural gas, commodity chemical and refined products. Similar remarks are valid for the physical recoverability of assets recognized in the balance sheet (deferred costs; see also "Item 18 note 3 Current assets of the Notes to the Consolidated Financial Statements) related to natural gas volumes not collected under long-term purchase contracts with take-or-pay clauses as well as for the recoverability of deferred tax assets. The amount of an impairment loss is determined by comparing the book value of an asset with its recoverable amount. The recoverable amount is the greater of fair value net of disposal cost or the value-in-use. The estimated value-in-use is based on the present values of expected future cash flows net of disposal costs. The expected future cash flows used for impairment analyses are based on judgmental assessments of future production volumes, prices and costs, considering available information at the date of review and are discounted by using a rate which considers the risks specific to the asset. For oil and natural gas properties, the expected future cash flows are estimated principally based on developed and non-developed proved reserves including, among other elements, production taxes and the costs to be incurred for the reserves yet to be developed. Oil, natural gas and petroleum product prices (and prices from products which are derived there from) used to quantify the expected future cash flows are estimated based on forward prices prevailing in the marketplace for the first four years and management s long-term planning assumptions thereafter. The estimate of the future amount of production is based on assumptions related to the commodity future prices, lifting and development costs, field decline rates, market demand and other factors. The discount rate reflects the current market valuation of the time value of money and of the specific risks of the asset not reflected in the estimate of the future cash flows. Goodwill and other intangible assets with an indefinite useful life are not subject to amortization. The Company tests for impairment such assets at the cash generating unit level on an annual basis and whenever there is an indication that they may be impaired. In particular, goodwill impairment is based on the lowest level (cash generating unit) to which goodwill can be allocated on a reasonable and consistent basis. A cash generating unit is the smallest aggregate on which the Company, directly or indirectly, evaluates the return on the capital expenditure. If the recoverable amount of a cash generating unit is lower than the carrying amount, goodwill attributed to that cash generating unit is impaired up to that difference; if the carrying amount of goodwill is lower than the amount of the impairment loss, the assets of the cash generating unit are impaired pro-rata on the basis of their carrying amount for the residual difference.

Asset retirement obligations

Obligations to remove tangible equipment and restore land or seabed require significant estimates in calculating the amount of the obligation and determining the amount required to be recorded presently in the Consolidated Financial Statements. Estimating future asset retirement obligations is complex. It requires management to make estimates and judgments with respect to removal obligations that will come to term many years into the future and contracts and regulations are often unclear as to what constitutes removal. In addition, the ultimate financial impact of environmental laws and regulations is not always clearly known as asset removal technologies and costs constantly evolve in the countries where Eni operates, as do political, environmental, safety and public expectations. The subjectivity of these estimates is also increased by the accounting method used that requires entities to record the fair value of a liability for an asset retirement obligation in the period when it is incurred (typically, at the time the asset is installed at the production location). When provisions are initially recognized, the related fixed assets are increased by an equal corresponding amount. Then, the carrying amount of provisions is adjusted to reflect the passage of time and any change in the estimates following the modification of future cash flows and discount rates adopted. The discount rate used to determine the provision is based on managerial judgments.

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Business combinations

Accounting for business combinations requires the allocation of the purchase price to the identifiable assets and liabilities of the acquired business at their fair values. Any positive residual difference is recognized as "Goodwill". Any negative residual difference is recognized in the profit and loss account. Management uses all available information to make these fair value measurements and, for major business combinations, engages independent external advisors.

Environmental liabilities

As other oil and gas companies, Eni is subject to numerous EU, national, regional and local environmental laws and regulations concerning its oil and gas operations, production and other activities. They include legislations that implement international conventions or protocols. Environmental costs are recognized when it becomes probable that a liability will be incurred and a reliable estimate can be made of the amount of the obligation. Management, considering the actions already taken, insurance policies obtained to cover environmental risks and provision for risks accrued, does not expect any material adverse effect on Eni s consolidated results of operations and financial position as a result of such laws and regulations. However, there can be no assurance that there will not be a material adverse impact on Eni s consolidated results of operations and financial position due to: (i) the possibility of an unknown contamination; (ii) the results of the ongoing surveys and other possible effects of statements required by applicable laws; (iii) the possible effects of future environmental legislations and rules; (iv) the effects of possible technological changes relating to future remediation; and (v) the possibility of litigation and the difficulty of determining Eni s liability, if any, against other potentially responsible parties with respect to such litigations and the possible reimbursements.

Provisions for employee benefits

Defined benefit plans are evaluated with reference to uncertain events and based upon actuarial assumptions including among others discount rates, expected rates of salary increases, medical cost trends, estimated retirement dates and mortality rates. The significant assumptions used to account for defined benefit plans are determined as follows: (i) discount and inflation rates reflect the rates at which benefits could be effectively settled, taking into account the duration of the obligation. Indicators used in selecting the discount rate include market yields on high quality corporate bonds (or, in the absence of a deep market of these bonds, on the market yields on government bonds). The inflation rates reflect market conditions observed country by country; (ii) the future salary levels of the individual employees are determined including an estimate of future changes attributed to general price levels (consistent with inflation rate assumptions), productivity, seniority and promotion; (iii) healthcare cost trend assumptions reflect an estimate of the actual future changes in the cost of the healthcare related benefits provided to the plan participants and are based on past and current healthcare cost trends including healthcare inflation, changes in healthcare utilization and changes in health status of the participants; and (iv) demographic assumptions such as mortality, disability and turnover reflect the best estimate of these future events for individual employees involved. Differences in the amount of the net defined benefit liability (asset), deriving from the remeasurements comprising, among others, changes in the current actuarial assumptions, differences in the previous actuarial assumptions and what has actually occurred and differences in the return on plan assets excluding amounts included in net interest, usually occur. Remeasurements are recognized within statement of comprehensive income for defined benefit plans and within profit and loss account for long-term plans.

Provisions for contingencies

In addition to environmental liabilities, asset retirement obligation and employee benefits, Eni recognizes provisions primarily related to litigations and tax issues. The estimate of these provisions is based on managerial judgments.

Revenue recognition

Revenue recognition in the Engineering & Construction segment is based on the stage of completion of a contract as measured on the cost-to-cost basis applied to contractual revenues. Use of the stage of completion method requires estimates of future gross profit on a contract-by-contract basis. The future gross profit represents the profit remaining after deducting costs attributable to the contract from revenues provided for in the contract. The estimate of future gross profit is based on a complex estimation process that includes identification of risks related to the geographical region where the activity is carried out, market conditions in that region and any assessment that is necessary to estimate with sufficient precision the total future costs, as well as the expected timetable to the end of the contract. Additional

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revenues, derived from a change in the scope of work, are included in the total amount of revenues when it is probable that the customer will approve the variation and the related amount. Claims deriving from additional costs incurred for reasons attributable to the customer are included in the total amount of revenues when it is probable that the counterparty will accept them.

Revenues from the sale of electricity and gas to retail customers include allocations for the supplies, occurred between the date of the last meters reading and the year end, not yet billed. These estimates are based on the difference between the volumes allocated by the grid managers and the billed volumes, as well as on other factors, considered by the management, which can impact on them.

2011-2013 Group results of operations

Overview of the profit and loss account for three years ended December 31, 2011, 2012 and 2013

The table below sets forth a summary of Eni s profit and loss account for the periods indicated. All line items included in the table below are derived from the Consolidated Financial Statements prepared in accordance with IFRS.

	Year ended December 31,		
	2011	2012	2013
	(euro million)		
Net sales from operations	107,690	127,109	114,697
Other income and revenues [1]	926	1,548	1,387
Total revenues	108,616	128,657	116,084
Operating expenses	(83,199)	(99,674)	(95,304)
Other operating (expense) income	171	(158)	(71)
Depreciation, depletion, amortization and impairments	(8,785)	(13,617)	(11,821)
OPERATING PROFIT	**16,803**	**15,208**	**8,888**
Finance income (expense)	(1,146)	(1,371)	(1,009)
Income (expense) from investments	2,123	2,789	6,085
PROFIT BEFORE INCOME TAXES	**17,780**	**16,626**	**13,964**
Income taxes	(9,903)	(11,679)	(9,005)
Net profit - continuing operations	**7,877**	**4,947**	**4,959**
Net profit - discontinued operations	**(74)**	**3,732**	
Net profit	**7,803**	**8,679**	**4,959**
Attributable to:			
Eni s shareholders:	6,860	7,790	5,160
- continuing operations	6,902	4,200	5,160

- discontinued operations	(42)	3,590	
Non-controlling interest:	943	889	(201)
- continuing operations	975	747	(201)
- discontinued operations	(32)	142	

(1) Includes, among other things, contract penalties, income from contract cancellations, gains on disposal of mineral rights and other fixed assets, compensation for damages and indemnities and other income.

The table below sets forth certain income statement items as a percentage of net sales from operations for the periods indicated.

	Year ended December 31,		
	2011	2012	2013
		(%)	
Operating expenses	77.3	78.4	83.1
Depreciation, depletion, amortization and impairments	8.2	10.7	10.3
OPERATING PROFIT	**15.6**	**12.0**	**7.7**

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2013 compared to 2012. Net profit attributable to Eni s shareholders from continuing operations in 2013 was euro 5,160 million, an increase of euro 960 million from 2012, or 22.9%. This increase was driven by:

(i) the recognition of gains on the divestment of an interest in the Mozambique exploration project and on the fair-value revaluation of Eni s stake in the Artic Russia joint venture (an overall gain of approximately euro 6 billion); and

(ii) lower income taxes (down euro 2,674 million compared to 2012 full year) currently payable by subsidiaries in the Exploration & Production segment operating outside Italy due to lower taxable profit.

These increases were partly offset by:

(i) a lowered operating performance (down by euro 6,320 million, or 41.6% from 2012) which was mainly reported by the Exploration & Production segment reflecting lower production sold impacted by geopolitical issues, as well as by the Engineering & Construction segment due to a worsening trading environment as well as customer relationship and management issues that began to emerge late in 2012 and fully materialize in the first half of 2013 resulting in a significant revision of margin estimates at certain large contracts for the construction of onshore industrial complexes. Also the Refining & Marketing and Chemical segments reported larger operating losses due to a demand downturn, competitive pressure driven by overcapacity and oversupplies and unprofitable unit margins. The Gas & Power segment reported slightly better results in spite of a continuing deterioration in the trading environment which can be explained by lower impairment losses; and

(ii) the lower operating performance was also affected by the recognition of inventory holding losses in particular in the Gas & Power, Refining & Marketing and Chemical segments (down euro 733 million from a year ago). Further information on inventory holding gains and losses is provided on page 114.

2012 compared to 2011. Net profit attributable to Eni s shareholders from continuing operations in 2012 was euro 4,200 million, a decrease of euro 2,702 million from 2011, or 39.2%. This decrease was driven by:

(i) a lower operating performance (down by euro 1,595 million, or 9.5% from 2011) which was mainly reported by the Gas & Power, Refining & Marketing and Chemical segments due to a downturn in demand, competitive pressure and unprofitable unit margins. Results also reflected higher impairments of property, plant and equipment and intangible assets, mostly in the gas marketing and refining businesses due to a reduced profitability outlook on the back of the ongoing European downturn. The negative factors were partly offset by better results reported by the Exploration & Production segment (up by 16.3%);

(ii) the lower operating performance was also affected by the recognition of lower inventory holding gains in particular in the Refining & Marketing and, to a minor extent, Gas & Power segments (down euro 1,096 million from a year ago). Further information on inventory holding gains and losses is provided on page 114; and

(iii) higher income taxes (up euro 1,776 million compared to 2011 full year) currently payable by subsidiaries in the Exploration & Production segment operating outside Italy due to higher taxable profit. The Company also recognized a write down of euro 1,030 million to reflect a lower likelihood that certain deferred tax assets of Italian subsidiaries can be recovered in future periods due to an expected reduction in taxable income generated in Italy, and as Eni has lost the availability of Snam taxable profit against which Italian tax assets can be utilized following the deconsolidation of Snam.

These decreases were partly offset by higher profits reported from equity-accounted and cost-accounted entities and financial assets, mainly reflecting the recording of gains on disposal and revaluation of interests relating to the divestment of part of Eni s interest in Galp (an overall gain of approximately euro 2 billion). These gains were partly offset by the fact that in 2011 Eni benefited from gains recorded on the divestment of Eni s interests in international gas pipelines (euro 1,044 million).

Discontinued operations

In accordance with IFRS 5, 2012 results of the Italian regulated businesses managed by Snam were reported as discontinued operations until loss of control on the entity which occurred in October 2012, as part of a transaction to divest a 30% interest less one share in Snam to an Italian entity, Cassa Depositi e Prestiti. The divestment took place in accordance with Article 15 of Law Decree No. 1 of January 24, 2012, enacted into Law No. 27 of March 24, 2012 which mandated the ownership unbundling of Snam. Prior year data have been modified accordingly.

In accordance with the guidelines of IFRS 5, assets and liabilities, results of operations and cash flow of the discontinued operations were reported separately from the Group s continuing operations, including gains on the disposal and the revaluation of the residual interest.

The table below sets forth net profit from discontinued operations for the periods indicated.

	Year ended December 31,		
	2011	2012	2013
	(euro million)		
Net profit - discontinued operations	**(74)**	**3,732**	
attributable to:			
- Eni	(42)	3,590	
- non-controlling interest	(32)	142	

In 2012, discontinued operations earned net profit of euro 3,732 million which mainly comprised the capital gain on the divestment of a 30% interest less one share in Snam to Cassa Depositi e Prestiti for euro 2,019 million and a revaluation gain of euro 1,451 million on the residual interest; both gains were subject to a limited tax under current Italian tax rules.

Profit earned by discontinued operations in previous reporting periods reflected the fact that Snam and its subsidiaries derived a large part of their revenues from intercompany transactions which profit margins were eliminated upon consolidation. As a result, the underlying profit or loss earned by the discontinued operations represented only profit or loss earned by the Group on transactions with third parties.

Year-on-year comparability of results from continuing operations in 2013 was affected by the fact that in 2012 Snam margins on intragroup transactions relating to the supply of gas transport and other services have been eliminated upon consolidation, while in 2013 those transactions were accounted as third-party transactions, thus affecting the Group operating costs and profits.

Analysis of the line items of the profit and loss account of continuing operations

a) Total revenues

Eni s revenues from continuing operations were euro 116,084 million, euro 128,657 million and euro 108,616 million for the year ended December 31, 2013, 2012 and 2011, respectively. Total revenues consist of net sales from operations and other income and revenues. Eni s net sales from operations from continuing operations amounted to euro 114,697 million, euro 127,109 million and euro 107,690 million for the year ended December 31, 2013, 2012 and 2011, respectively, and its other income and revenues totaled euro 1,387 million, euro 1,548 million and euro 926 million, respectively, in these periods.

Net sales from operations from continuing operations

The table below sets forth, for the periods indicated, the net sales from operations from continuing operations generated by each of Eni s business segments including intragroup sales, together with consolidated net sales from operations.

	Year ended December 31,		
	2011	2012	2013
	(euro million)		
Exploration & Production	29,121	35,874	31,264
Gas & Power [(1)]	33,093	36,198	32,212
Refining & Marketing	51,219	62,531	57,238
Chemicals	6,491	6,418	5,859
Engineering & Construction	11,834	12,799	11,598
Other activities	85	119	80
Corporate and financial companies	1,365	1,369	1,453
Impact of unrealized intragroup profit elimination [(2)]	(54)	(75)	18
Consolidation adjustments [(3)]	(25,464)	(28,124)	(25,025)
NET SALES FROM OPERATIONS	**107,690**	**127,109**	**114,697**

(1) Following the deconsolidation of Snam in 2012, the Gas & Power segment only includes the results of the Marketing and the International transport activities for all periods presented.
(2) This item mainly pertains to intragroup sales of commodities and capital assets recorded at period end in the assets of the purchasing business segment.
(3) Intragroup sales are included in net sales from operations in order to give a more meaningful indication as to the volume of the activities to which sales from operations by segment may be related. The most substantial intragroup sales are recorded by the Exploration & Production segment. See "Item 18 note 35 Guarantees, commitments and risks of the Notes to the Consolidated Financial Statements" for a breakdown of intragroup sales by segment for the reported years.

2013 compared to 2012. Eni s net sales from operations (revenues) from continuing operations for 2013 (euro 114,697 million) decreased by euro 12,412 million from 2012 (or down 9.8%) primarily reflecting lower realizations on oil, products and natural gas in dollar terms, the negative impact of the appreciation of the euro against the U.S. dollar, lower volumes in all business segments and a slowdown in the Engineering & Construction business activity.

Revenues generated by the Exploration & Production segment (euro 31,264 million) decreased by euro 4,610 million (or down 12.9%) due to lower oil and gas realizations in dollar terms (down by 2.1%), the appreciation of the euro against the U.S. dollar and the extraordinary disruptions in Libya and Nigeria, which negatively impacted revenues by approximately the same amounts.

Revenues generated by the Gas & Power segment (euro 32,212 million) decreased by euro 3,986 million (or down 11.0%) due to a continued deterioration in selling prices reflecting a weak gas demand and increasing competitive pressure. Particularly, spot prices at Italian hubs have aligned very rapidly to continental hubs, thus driving a large fall in Eni s average realizations as spot prices have become the main indexation benchmark of selling prices in short-term supplies to large Italian customers. Revenues were also impacted by the price revisions that were agreed with the Company s Italian long-term buyers whereby contractual prices were aligned to spot prices. Finally, the segment recorded lower sales volumes to European target markets.

Revenues generated by the Refining & Marketing segment (euro 57,238 million) decreased by euro 5,293 million (or down 8.5%) mainly reflecting lower volumes of refined products (down 4.84 mmtonnes, or 10%, from 2012) and the negative impact of the currency.

Revenues generated by the Chemical segment (euro 5,859 million) decreased by euro 559 million (down 8.7%) from 2012 mainly due to a decline in volumes sold (down by 4.2%) against the backdrop of continuing weak commodity demand, which was impacted by the economic downturn, and declining average sales prices (down by 3.2%).

Revenues generated by the Engineering & Construction segment (euro 11,598 million) decreased by euro 1,201 million, or 9.4%, as a result of a decline in business activities in the segments of Onshore E&C and Offshore E&C.

2012 compared to 2011. Eni s net sales from operations (revenues) from continuing operations for 2012 (euro 127,109 million) increased by euro 19,419 million from 2011 (or up 18.0%) primarily reflecting higher realizations on oil, products and natural gas in dollar terms and the positive impact of the appreciation of the U.S. dollar against the euro.

Revenues generated by the Exploration & Production segment (euro 35,874 million) increased by euro 6,753 million (or up 23.2%) due to higher volumes of production sold following a production recovery in Libya, higher realizations in dollar terms (oil up 0.5%; natural gas up 9.9%), as well as currency translation effects.

Revenues generated by the Gas & Power segment (euro 36,198 million) increased by euro 3,105 million (or up 9.4%) due to trends in energy parameters which are reflected in gas prices to the retail segment mainly in Italy where retail prices are linked to the price of oil and certain refined products with certain time lags. Also a slight recovery in spot prices recorded at European continental hubs benefited revenues in this segment.

Revenues generated by the Refining & Marketing segment (euro 62,531 million) increased by euro 11,312 million (or up 22.1%) mainly reflecting higher average selling prices of refined products and the positive impact of the appreciation of the U.S. dollar against the euro, as well as higher sales volumes (up 3.31 mmtonnes, or 7.4%).

Revenues generated by the Chemical segment (euro 6,418 million) decreased by euro 73 million (or down 1.1%) from 2011 mainly due to a decline in volumes sold (down 2.1%) reflecting continuing weakness in commodity demand, which was partly offset by slightly better average sale prices.

Revenues generated by the Engineering & Construction segment (euro 12,799 million) increased by euro 965 million, or 8.2%, as a result of increased activities in the Engineering & Construction business, mainly in the Middle and Far East.

b) Operating expenses

The table below sets forth the components of Eni s operating expenses for the periods indicated.

	Year ended December 31,		
	2011	2012	2013
	(euro million)		
Purchases, services and other	78,795	95,034	90,003
Payroll and related costs	4,404	4,640	5,301
Operating expenses	**83,199**	**99,674**	**95,304**

2013 compared to 2012. Operating expenses from continuing operations for the year (euro 95,304 million) decreased by euro 4,370 million from 2012, down 4.4%, primarily reflecting lower supply costs of raw materials due to the appreciation of the euro against the U.S. dollar as the Company purchases of gas, refinery and chemical feedstock are indexed to U.S. dollar-denominated prices of crude oil and products, as well as the benefits of the renegotiations of long-term gas supply contracts, some of which were retroactive to previous reporting periods.

Purchases, services and other costs included environmental and onerous contracts risk provisions, net of reversal of unused provisions, amounting to euro 539 million, a large part of which related to the expected losses of an onerous contract in a re-gasification project (for more information see "Item 18 note 35 Guarantees, commitments and risks of the Notes to the Consolidated Financial Statements"). The reduction reflected also the circumstance that in 2012 a risk provision amounting to euro 945 million was incurred in connection with price revisions at long-term gas purchase contracts relating to gas volumes purchased in previous reporting periods, including the provision relating to the settlement of an arbitration proceeding with GasTerra.

Payroll and related costs (euro 5,301 million) increased by euro 661 million, or 14.2%, from 2012 due to a higher average number of employees outside Italy particularly in the Engineering & Construction segment and higher provision for redundancy incentives (euro 270 million), which included Eni s cost for 2013-2014 redundancy, pursuant to the provisions of Law No. 223/1991.

2012 compared to 2011. Operating expenses from continuing operations for the year (euro 99,674 million) increased by euro 16,475 million from 2011, up 19.8%, primarily reflecting higher supply costs of purchased gas, and refinery and chemical feedstock reflecting trends in the oil environment and the appreciation of the dollar against the euro.

Purchases, services and other costs included risk provisions amounting to euro 945 million incurred in connection with price revisions at long-term gas purchase contracts relating to gas volumes purchased in previous reporting periods, including the provision relating to the settlement of an arbitration proceeding with GasTerra (for detailed information see "Item 4 Gas & Power"), as well as environmental and other risk provisions. The unfavorable ruling in the arbitration proceeding with GasTerra also impacted the cost of gas volumes purchased in the year, as well as the cost that the Company expects to incur in future reporting periods unless Eni is successful in renegotiating pricing terms.

Payroll and related costs (euro 4,640 million) increased by euro 236 million, or 5.4%, from 2011 due to a higher average number of employees outside Italy (following higher activity levels in the Engineering & Construction and Exploration & Production segments) and higher unit labor cost outside Italy and the appreciation of the dollar against the euro. These increases were partly offset by a reduction in the average number of employees in Italy and a lower provision for redundancy incentives.

c) Depreciation, depletion, amortization and impairments

The table below sets forth a breakdown of depreciation, depletion, amortization and impairments by business segment for the periods indicated.

	Year ended December 31,		
	2011	**2012**	**2013**
		(euro million)	
Exploration & Production [(1)]	6,251	7,985	7,810
Gas & Power [(2)]	413	480	413
Refining & Marketing	351	366	345
Chemicals	90	90	95
Engineering & Construction	596	683	721
Other activities	2	1	1
Corporate and financial companies	75	65	61
Impact of unrealized intragroup profit elimination [(3)]	(23)	(25)	(25)
Total depreciation, depletion and amortization	**7,755**	**9,645**	**9,421**
Impairments	1,030	3,972	2,400
	8,785	**13,617**	**11,821**

(1) Exploration expenditures of euro 1,736 million, euro 1,835 million and euro 1,165 million are included in these amounts and related to the years 2013, 2012 and 2011, respectively.
(2) Following the deconsolidation of Snam in 2012, the Gas & Power segment only includes the results of the Marketing and the International Transport activities for all periods presented.
(3) This item concerned mainly intragroup sales of goods and capital, recorded at period end in the assets of the purchasing business segment.

2013 compared to 2012. In 2013, depreciation, depletion and amortization charges (euro 9,421 million) decreased by euro 224 million from 2012, or 2.3%, mainly in the Exploration & Production segment (euro 175 million) reflecting lower production volumes mainly in Libya and Nigeria and the appreciation of the euro against the U.S. dollar which reduced the reported amounts of the Company subsidiaries which use the U.S. dollar as functional currency.
The increase recorded in the Engineering & Construction segment (up euro 38 million, or 5.6%) was due to new vessels and rigs which were brought into operations.

In 2013, impairments charges of euro 2,400 million mainly related to the Gas & Power and the Refining & Marketing segments. In the Gas & Power segment, goodwill and other intangible assets allocated to the gas marketing activity in Europe were impaired for euro 480 million which completely wrote down the carrying amounts of goodwill and other intangibles which were recognized upon the Distrigas acquisition in 2008. Power generation plants were impaired for euro 919 million and refineries for euro 633 million. Those impairments losses were driven by a reduced profitability outlook which was impacted by structural headwinds in the gas and petroleum products industries due to weak demand prospects, excess supplies and overcapacity and continued competitive pressure which have resulted in the projections of lower values-in-use than the carrying amounts of the impaired assets. Other impairment losses were incurred at a number of oil&gas properties in the Exploration & Production segment (euro 19 million, net of reversal of previous impairment losses) reflecting mainly downward reserve revisions, as well as marginal lines of business in the Chemical segment (euro 44 million) due to lack of profitability perspectives.

2012 compared to 2011. In 2012, depreciation, depletion and amortization charges (euro 9,645 million) increased by euro 1,890 million from 2011, or 24.4%, mainly in the Exploration & Production segment (up euro 1,734 million) reflecting higher output levels in Libya, following an ongoing recovery in activities, rising capitalized expenses incurred in connection with ongoing exploration activities, the start-up of new fields and the appreciation of the U.S. dollar against the euro (up 7.7%). The increase recorded in the Engineering & Construction segment (up euro 87 million, or 14.6%) was due to new vessels and rigs which were brought into operations.

In 2012, impairments charges of euro 3,972 million mainly related to goodwill and other intangible assets in the gas marketing activity (euro 2,443 million) and impairment losses of refining plants (euro 843 million). In performing the impairment review, management assumed a reduced profitability outlook in those businesses driven by a deteriorating European macroeconomic environment, volatility in commodity prices and margins, and rising competitive pressures. Other impairment losses were incurred at a number of proved and unproved properties in the Exploration & Production segment (euro 547 million) reflecting downward reserves revisions, price changes and revised profitability outlook mainly at certain oil and gas assets in the United States, a gas asset in India and an oil asset in Turkmenistan, as well as marginal lines of business in the Chemical segment (euro 112 million) due to lack of profitability prospects.

d) Operating profit by segment

The table below sets forth Eni s operating profit from continuing operations by business segment for the periods indicated.

	Year ended December 31,		
	2011	2012	2013
	(euro million)		
Exploration & Production	15,887	18,470	14,868
Gas & Power [(1)]	(326)	(3,125)	(2,967)
Refining & Marketing	(273)	(1,264)	(1,492)
Chemicals	(424)	(681)	(725)
Engineering & Construction	1,422	1,453	(98)
Other activities	(427)	(300)	(337)
Corporate and financial companies	(319)	(341)	(399)
Impact of unrealized intragroup profit elimination	1,263	996	38
Operating profit	**16,803**	**15,208**	**8,888**

(1) Following the deconsolidation of Snam in 2012, the Gas & Power segment only include the results of the Marketing and the International Transport activities for all periods presented.

The table below sets forth operating profit from continuing operations for each of Eni s business segments as a percentage of each segment s net sales from operations from continuing operations (including intragroup sales) for the periods presented.

	Year ended December 31,		
	2011	2012	2013
	(euro million)		
Exploration & Production	54.6	51.5	47.6
Gas & Power	(1.0)	(8.6)	(9.2)

Refining & Marketing	(0.5)	(2.0)	(2.6)
Chemicals	(6.5)	(10.6)	(12.4)
Engineering & Construction	12.0	11.4	(0.8)
Other activities		(252.1)	(421.3)
Corporate and financial companies	(23.4)	(24.9)	(27.5)
Group	**15.6**	**12.0**	**7.7**

Exploration & Production. Operating profit in 2013 amounted to euro 14,868 million, down by euro 3,602 million from 2012, or 19.5%. The decline was principally due to lower volumes of sold production which was impacted by extraordinary disruptions mainly in Libya and Nigeria. Also results reported by non-euro subsidiaries were impacted by the appreciation of the euro against the U.S. dollar in the conversion of dollar-denominated results of operations (approximately euro 560 million), as well as lower oil and gas realizations in dollar terms (down by 2.1%, on average).

In 2013, the Company s liquids and gas realizations decreased on average by 2.1% in dollar terms, driven by a decline in international oil prices for market benchmarks (Brent crude price decreased by 2.6%). Eni s average oil realizations decreased on average by 3.1%. Eni s average gas realizations increased by 1.9%.

Operating profit in 2012 amounted to euro 18,470 million, up euro 2,583 million from 2011, or 16.3%, due to an ongoing recovery in Libyan activities which came almost to a halt in 2011. In fact the 2011 production performance was negatively impacted by disruptions in the Company s output from Libyan fields due to the internal conflict that occurred in 2011 and the consequent declaration of force majeure on the execution of the petroleum contracts in Country throughout the duration of the internal crisis.

The 2012 result of the Exploration & Production segment also benefited from the appreciation of the U.S. dollar over the euro for an estimated amount of approximately euro 1,100 million. These positives were partly offset by higher exploration costs incurred due to increased activities, as well as higher operating costs and depreciation charges in connection with new field start-ups/ramp-ups.

In 2012, the Company s liquids and gas realizations increased on average by 1.6% in dollar terms, driven by oil prices for market benchmarks (Brent crude price increased by 0.3%). Eni s average oil realizations increased on average by 0.5%. Eni s average gas realizations increased by 9.9%, due to time lags in oil-linked pricing formulas which were recorded in certain geographic areas, whereas gas spot prices declined in other areas, mainly in the U.S. market.

The operating profit of Exploration & Production segment included the following gains and charges:

	Year ended December 31,		
	2011	**2012**	**2013**
		(euro million)	
Impairment losses	(190)	(550)	(19)
Risk provisions		(7)	(7)
Net gains on disposal of assets	63	542	283
Provision for redundancy incentives	(44)	(6)	(52)
Fair value gains/losses on commodity derivatives	(1)	(1)	2
Other	(18)	(54)	16
	(190)	**(76)**	**223**

In reviewing the performance of the Company s business segments, management generally excludes the gains and losses listed above in order to assess the underlying industrial trends and obtain a better comparison of base business performance across reporting periods.

Gas & Power. In 2013, the Gas & Power segment reported an operating loss of euro 2,967 million, which reflected impairment losses of euro 1,685 million and unprofitable gas selling margins for the remaining amount, particularly in the Italian market. The Gas & Power operating loss improved by euro 158 million from 2012, when this segment reported an operating loss of euro 3,125 million. The 2012 loss was restated by a positive euro 94 million amount due to the adoption in 2013 of the new accounting standard IFRS 11 whereby Eni recognizes, on a line-by-line basis in the Consolidated Financial Statements, its share of the assets, liabilities and expenses of joint operations incurred jointly with the other partners, along with the Group s income from the sale of its share of the output and any liabilities and expenses that the Group has incurred in relation to the joint operation. See "Item 18 note 2 Principles of consolidation of the Notes to the Consolidated Financial Statements". Prior year data have not been restated.

This business has been negatively affected by structural headwinds in the European gas sector in the latest three fiscal years due to continued deterioration in demand, gas oversupplies and unabated competitive pressure which have impacted selling margins. The modest improvement recorded in 2013 compared to 2012 was due to the recognition of lower asset impairments. These losses were mainly incurred by the Marketing business. The International Transport business operating profit declined by euro 144 million from 2012, or 43.4%.

The loss recorded by the Marketing business in 2013 was driven by a demand downturn and escalating competitive pressures fuelled by oversupplies in the marketplace, the effects of which were exacerbated by minimum collection obligations provided by long-term supply contracts, which impacted our operations both in Italy and outside Italy. Based on these trends, Eni s gas business in Italy was impacted by plummeting prices realized on short-term selling contracts to large Italian clients because those prices were benchmarked to Italian spot prices which swiftly aligned to continental hubs determining negative margins in comparison with oil-linked supply costs. The decline in spot prices was transferred to long-term selling contracts to certain Italian buyers, whereby Eni had those buyers agreed to revise the contractual price of the suppliers to align to spot prices. Furthermore, Eni s results were impacted by sharply lower margins in the production and sale of gas-fired electricity due to oversupply and increasing competition from more competitive sources such as coal-fired electricity and renewables. The reduced profitability outlook in this business due to changed underlying fundamentals also resulted in the write down of power plants (euro 919 million); in addition goodwill and other intangibles which were recognized as part of certain business combinations in the gas marketing business were impaired due to a reduced profitability outlook. These negative trends were partly offset by the positive effects of price revisions at certain long-term gas suppliers, some of which were retroactive to the previous reporting period.

In 2012, the Gas & Power segment reported an operating loss of euro 3,125 million, materially down from 2011, when this segment reported an operating loss of euro 326 million. Those sharply higher losses were mainly incurred by the Marketing business, while the International Transport business remained profitable albeit reporting a lower profit compared to 2011 due to the divestment of Eni s interests in the entities engaged in the transport of gas from Northern Europe and Russia which was completed in 2011.

The negative performance in the Marketing business was driven by a demand downturn and escalating competitive pressures fuelled by oversupplies in the marketplace which impacted our operations both in Italy and outside Italy. The reduced profitability outlook in this business due to changed underlying fundamentals also resulted in the write down of goodwill and other intangibles which were recognized as part of certain business combinations, among which Distrigas in 2008 and other minor European gas marketing companies in later years (Altergaz in France). Operating profit was also impacted by the negative effects of price revisions at certain long-term gas suppliers and customers; this was also due to the settlement of a number of arbitration proceedings, including settlement of an arbitration proceeding with GasTerra.

However, excluding impairment losses and the risk provisions accrued in connection with the above mentioned arbitration proceedings involving price revisions for gas volumes purchased in previous reporting periods, the Gas Marketing business underlying results improved compared to 2011. Those trends benefited from the renegotiation of better economic terms for certain supply contracts, including the recognition of better supply costs retroactive to the beginning of 2011, and an ongoing recovery in Libyan supplies which improved the average costs of gas supplies to the Company compared to the 2011 performance.

The table below sets forth the breakdown of operating profit (loss) by businesses in the Gas & Power segment:

	Year ended December 31,		
	2011	**2012**	**2013**
	(euro million)		
Marketing	(710)	(3,457)	(3,155)
International transport	384	332	188
Operating profit of the Gas & Power segment	**(326)**	**(3,125)**	**(2,967)**

The operating profit of the Gas & Power segment included the following gains and charges:

	Year ended December 31,		
	2011	**2012**	**2013**
	(euro million)		

Profit (loss) on stock	166	(163)	(191)
Environmental provisions		2	1
Impairment losses	(154)	(2,443)	(1,685)
Net gains on disposal of assets		3	(1)
Risk provisions	(77)	(831)	(292)
Provision for redundancy incentives	(34)	(5)	(10)
Fair value gains/losses on commodity derivatives	(45)		(314)
Other	(17)	(138)	(23)
	(161)	**(3,575)**	**(2,515)**

In reviewing the performance of the Company s business segments, management generally excludes the gains and losses listed above in order to assess the underlying industrial trends and obtain a better comparison of base business performance across reporting periods. We note unprecedented amounts of impairment losses which were recorded both in 2013 and 2012 with euro 1,685 million and euro 2,443 million, respectively. Those impairment losses were recorded at the Company s cash generating unit European market impacting goodwill and other intangibles which were

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recognized upon prior-years business combinations and power generation plants. The driver of those losses were a reduced profitability outlook in the business due to continuing demand weakness, strong competitive pressures and ongoing oversupplies which are expected to hurt the Company s prices and selling margins for the foreseeable future. For further information see "Item 18 notes 15 "Property, plant and equipment" and 17 "Intangible assets" of the Notes to the Consolidated Financial Statements". Risk provisions presented in the table above mainly related to the expected future losses related to an onerous contract for a LNG re-gasification project due to the fact that the Company and its partner discontinued the project, while in 2012 they related to price revisions on the renegotiation of certain long-term supply contracts which contractual time span for price revisions expired in previous periods and within limits of volumes purchased in prior reporting periods, also due to the settlement of arbitration proceedings.

Refining & Marketing. In 2013, the Refining & Marketing segment reported an operating loss of euro 1,492 million, down by euro 228 million, or 18%, from 2012 when a loss of euro 1,264 million was incurred. The 2012 loss was restated by a positive euro 32 million amount due to the adoption in 2013 of the new accounting standard IFRS 11 whereby Eni recognizes, on a line-by-line basis in the Consolidated Financial Statements, its share of the assets, liabilities and expenses of joint operations incurred jointly with the other partners, along with the group s income from the sale of its share of the output and any liabilities and expenses that the group has incurred in relation to the joint operation. See "Item 18 note 2 Principles of consolidation of the Notes to the Consolidated Financial Statements". Prior year data have not been restated.

2013 marked the third consecutive year of losses at this business. This negative trend reflected structural weaknesses in the European refining industry which was negatively impacted by falling demand, overcapacity and increasing competition from streams of refined products coming from Russia, Asia and the United States. There were also company-specific issues; particularly the Company was impacted by reduced flows of heavy crudes in the Mediterranean Area which squeezed price differentials between the heavy qualities supplied by Eni s operations and the Brent market benchmark resulting in sharply lower margins in complex cycles.

In 2013, this negative scenario was partly counteracted by efficiency initiatives, in particular those aimed at reducing energy and operating costs and optimizing refinery utilization rates by reducing the throughput of less competitive plants. Marketing results registered a decline compared to the previous year, due to lower consumption in the retail market. The 2013 operating loss in the Refining & Marketing segment was also affected by material impairment losses (down by euro 633 million) which were recorded at refining plants due to management s business outlook that points to continuing weak fundamentals and unprofitable margins resulting in the projection of lower future cash flows than the assets carrying amounts. Furthermore, the segment reported an inventory holding loss (stock loss) from 2012, down to euro 221 million from a gain of euro 29 million.

Inventory holding gains or losses represent the difference between the cost of sales of the volumes sold during the period calculated using the cost of supplies incurred during the same period and the cost of sales calculated using the weighted average cost method. Under the weighted average cost method, which we use for IFRS reporting, the cost of inventory charged to the income statement is based on its historic cost of purchase, or manufacture, rather than its replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed represent the difference between the charge (to the income statement) for inventory on a weighted average cost method basis (after adjusting for any related movements in net realizable value provisions) and the charge that would have arisen if an average cost of supplies was used for the period. For this purpose, the average cost of supplies during the period is principally calculated on a quarterly or monthly basis by dividing the total cost of inventory acquired in the period by the number of barrels acquired. The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions.

In 2012, the Refining & Marketing segment reported an operating loss of euro 1,264 million, down by euro 991 million, compared to a loss of euro 273 million in 2011. The loss was driven by unprofitable refining margins due to an ongoing demand downturn for refined products, particularly in Italy, and excess capacity which prevented product prices from fully absorbing high supply costs of oil-based feedstock and oil-linked plant utilities. The 2012 operating loss in the Refining & Marketing segment was also affected by material impairment losses (down by euro 846 million) which were recorded at refining plants due to management s business outlook that points to continuing weak fundamentals and unprofitable margins resulting in the projection of lower future cash flows. Furthermore, the segment reported a much lower inventory holding gain (stock profit) from 2011, down to euro 29 million from euro 907 million. However, excluding asset impairments and a negative change in the inventory holding gain, the segment underlying results of operations improved compared to 2011. That trend reflected a slightly more favorable refining scenario as the benchmark margin on 2012 Brent crude rose by 2.77 $/BBL from 2011 and as management continued to focus on achieving efficiency gains, optimization measures and reduced refinery downtime. The Marketing activity reported lower results, due to lower retail and wholesale demand for gasoline and gasoil, and other products impacted by the economic downturn and high competitive pressure. Results were also affected by increased expenses associated with certain marketing initiatives including a special discount on prices at the pump during the summer week-ends in Italy.

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The operating profit of the Refining & Marketing segment included the following gains and charges:

	Year ended December 31,		
	2011	2012	2013
	(euro million)		
Profit (loss) on stock	907	29	(221)
Environmental provisions	(34)	(40)	(93)
Impairment losses	(488)	(846)	(633)
Net gains on disposal of assets	(10)	(5)	9
Risk provisions	(8)	(49)	
Provision for redundancy incentives	(81)	(19)	(91)
Fair value gains/losses on commodity derivatives	3		(5)
Other	(27)	(53)	(3)
	262	**(983)**	**(1,037)**

In reviewing the performance of the Company s business segments, management generally excludes the gains and losses listed above in order to assess the underlying industrial trends and obtain a better comparison of base business performance across reporting periods. We note that losses listed above include material impairment losses of refining plants due to the management s business outlook that points to continuing weak fundamentals and unprofitable margins resulting in the projection of lower future cash flows. Furthermore, we regard the inventory holding gain as lacking correlation to the underlying business performance which we track by matching revenues with current costs of supplies.

Chemicals. In 2013, the Chemical segment reported a slight deterioration in the operating loss, down by euro 44 million, or 6.5%, compared to 2012 (from a loss of euro 681 million in 2012 to a loss of euro 725 million in 2013). This negative performance was driven by falling commodity demand due to the economic downturn and increasing competition from Asian producers which impacted product margins and sales volumes which remained at depressed levels. Sales volumes decreased by 4.3%. Furthermore, the segment reported a much higher inventory holding loss (stock loss) from 2012, down to euro 213 million from euro 63 million.

In 2012, the Chemical segment incurred a larger operating loss, down by euro 257 million, or 60.6%, compared to 2011 (from a loss of euro 424 million in 2011 to a loss of euro 681 million in 2012). This negative performance was driven by falling commodity demand due to the economic downturn and unprofitable product margins of oil-based commodities which were squeezed by high crude oil costs, as signaled by a negative benchmark margin of cracking. Sales volumes decreased by 2.1%.

	Year ended December 31,		
	2011	2012	2013
	(euro million)		
Profit (loss) on stock	40	(63)	(213)
Settlement/payments on Antitrust and other authorities proceedings	(10)		
Environmental provisions	(1)		(61)
Impairment losses	(160)	(112)	(44)
Risk provisions		(18)	(4)

Net gains on disposal of assets		(1)	
Provision for redundancy incentives	(17)	(14)	(23)
Fair value gains/losses on commodity derivatives		(1)	1
Other	(3)		
	(151)	**(209)**	**(344)**

In reviewing the performance of the Company s business segments, management generally excludes the gains and losses listed above in order to assess the underlying industrial trends and obtain a better comparison of base business performance across reporting periods.

Engineering & Construction. In 2013, the Engineering & Construction segment registered sharply lower results recording an operating loss of euro 98 million compared to operating profit of euro 1,453 million recorded in 2012 (down euro 1,551 million). This result reflected a worsening trading environment, as well as customer relationship and management issues that began to emerge late in 2012 and fully materialize in the first half of 2013, resulting in a sharply lower revision of margin estimates at certain large contracts for the construction of onshore industrial complexes, as well as a slowdown in order acquisitions in Onshore and Offshore Engineering & Construction businesses.

Operating profit in 2012 amounted to euro 1,453 million, substantially in line with the previous year result (up euro 31 million, or 2.2% compared to 2011). This result reflected higher revenues and better margins on the works executed, mainly in the third quarter of 2012, in the Engineering & Construction business unit, in the Middle and Far East, as well as in Offshore Drilling, where the Scarabeo 8 and Scarabeo 9 activity compensated the negative impact of the upgrade shutdown of the semi-submersible platforms Scarabeo 3 and Scarabeo 6. However, from the second half of 2012, business trends commenced to reverse due to reduced activity and a slowdown in new orders acquisitions mainly in the Onshore E&C and Offshore E&C businesses, leading the Company to negatively revise the profitability outlook for 2013.

The operating profit of Engineering & Construction segment included the following gains and charges:

	Year ended December 31,		
	2011	**2012**	**2013**
		(euro million)	
Impairment losses	(35)	(25)	
Net gains on disposal of assets	(4)	(3)	(107)
Provision for redundancy incentives	(10)	(7)	(2)
Fair value gains/losses on commodity derivatives	28	3	1
Other			109
	(21)	**(32)**	**1**

Other activities. This reporting segment includes the results of operations of Eni s subsidiary Syndial which runs minor petrochemical activities and reclamation and decommissioning activities pertaining to certain businesses which Eni exited, divested or liquidated in past years.

This subsidiary reported operating losses of euro 337 million for 2013, euro 300 million for 2012 and euro 427 million for 2011. The magnitude of losses was mainly influenced by the recognition of risk provisions mainly related to environmental issues and litigation whose breakdown is provided below. See "Item 4 Environmental regulation" for further details.

	Year ended December 31,		
	2011	**2012**	**2013**
		(euro million)	
Loss provisions on Antitrust and other authorities proceedings	(59)		
Environmental provisions	(141)	(25)	(52)
Impairment losses	(4)	(2)	(19)
Net gains on disposal of assets	7	12	3
Risk provisions	(9)	(35)	(31)
Provision for redundancy incentives	(8)	(2)	(20)
Other	13	(26)	(8)

	(201)	**(78)**	**(127)**

In addition to the above listed charges, losses for the reporting periods presented derived from a marginal line of business that the Company is planning to shut down.

Corporate and financial companies. These activities are mainly cost centers which comprise corporate activities and central treasury departments and financial and other subsidiaries that provide a range of financial and business support services to Group companies, including financing of Eni s projects worldwide, information technology, legal affairs, corporate secretary, employee selection, training and retention, real estate and other general purpose services.

The aggregate Corporate and financial companies reported an operating loss of euro 399 million for 2013, representing an increase of euro 58 million, compared to the loss recorded in 2012 (euro 341 million), mainly reflecting the recognition of other risk provisions which were partly offset by the implementation of cost efficiency measures.

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The aggregate Corporate and financial companies reported an operating loss of euro 341 million for 2012, representing an increase of euro 22 million, compared to the loss recorded in 2011 (euro 319 million), mainly reflecting the recognition of other risk provisions.

e) Net finance expense

The table below sets forth a breakdown of Eni s net financial expense for the periods indicated:

	Year ended December 31,		
	2011	2012	2013
	(euro million)		
Gain (loss) on derivative financial instruments	(112)	(252)	(92)
Exchange differences, net	(111)	131	37
Net income from financial activities held for trading			4
Interest income	22	28	43
Finance expense on short and long-term debt	(922)	(986)	(923)
Finance expense due to the passage of time	(235)	(308)	(240)
Other finance income and expense, net	100	(134)	(8)
	(1,258)	**(1,521)**	**(1,179)**
Finance expense capitalized	112	150	170
	(1,146)	**(1,371)**	**(1,009)**

2013 compared to 2012. In 2013, net finance expense was euro 1,009 million, down by euro 362 million compared to 2012 reflecting lower finance expense on borrowings (down euro 63 million) due to lower market interests and lower losses recognized in fair value evaluation of certain derivative instruments on interest rates (euro 92 million loss in 2013 compared to euro 252 million loss in 2012) which did not meet the formal criteria to be designated as hedges under IFRS. Negative exchange differences net (down euro 94 million) were partly offset by lower losses on exchange rate derivatives (up euro 160 million). Other finance expense decreased by euro 126 million from 2012 mainly due to the fact that the 2012 results reflected finance charges accrued on amounts due to certain gas suppliers following the definition of contractual price revisions.

2012 compared to 2011. In 2012, net finance expense was euro 1,371 million, up by euro 225 million compared to 2011 due to negative estimate revisions of certain discounted provisions due to a changed interest rate environment recorded in the line item Finance expense due to the passage of time (down by euro 73 million), higher finance charges (down by euro 64 million) and other finance expense (down by euro 234 million) reflecting finance charges accrued on amounts due to certain gas suppliers following the definition of contractual price revisions. The higher balance of gains and losses due to exchange differences (up by euro 242 million) was partly offset by losses on exchange rate derivatives recognized through profit as lacking the formal criteria for hedge accounting. Finally, a loss of euro 26 million was recognized on the fair value evaluation of a call option embedded in a convertible bond whose underlying shares were represented by a stake in Galp equaling to 8% of the share capital of the investee. This loss was matched by a market fair value gain through profit which was recorded on the Galp shares underlying the convertible bond and reported in the line item Income on investments .

f) Net income from investments

2013 compared to 2012. Net income from investments in 2013 was a net gain of euro 6,085 million and mainly related to: (i) gains on disposal of assets, in particular the gain recorded on the sale of a 28.57% interest in Eni East Africa, which is the operator of Area 4 in Mozambique, to China National Petroleum Corp (euro 3,359 million), and the fair-value revaluation of Eni s interest in Artic Russia (euro 1,682 million) due to the fact that joint control was lost over the investee following the satisfaction, before year end, of all conditions precedent to the Sale and Purchase Agreement signed with Gazprom in November 2013. The consideration for the disposal was received in January 2014; (ii) Eni s share of profit of entities accounted for under the equity-accounting method (euro 222 million), mainly in the Exploration & Production and Gas & Power segments; and (iii) dividends received from entities accounted for at cost (euro 400 million), relating to Nigeria LNG Ltd (euro 224 million), Snam SpA (euro 72 million) and Galp Energia SGPS SA (euro 43 million). These gains are further explained in Item 18 note 18 Investments of the Notes to the Consolidated Financial Statements .

2012 compared to 2011. Net income from investments in 2012 was a net gain of euro 2,789 million and mainly related to: (i) Eni s share of profit of entities accounted for under the equity-accounting method (euro 186 million) mainly in the Gas & Power segment; (ii) dividends received by entities accounted for at cost (euro 431 million); (iii) gains on disposal of assets (euro 349 million) mainly relating to the divestment of a 9% interest in Galp (euro 311 million) in two trances (a 5% interest sold to Amorim BV and a 4% sold to institutional investors through an accelerated book-building procedure in November 2012); and (iv) other net income (euro 1,823 million) which reflected revaluation gains recorded on the Company s interest in Galp. Those gains are further explained in "Item 18 note 18 Investments of the Notes to the Consolidated Financial Statements".

g) Taxes

2013 compared to 2012. In 2013, income taxes amounted to euro 9,005 million, down by euro 2,674 million compared to 2012, or 22.9%, mainly reflecting lower income taxes currently payable by subsidiaries in the Exploration & Production segment operating outside Italy due to a declining taxable profit. The Company recognized a write down of euro 954 million of deferred tax assets to reflect a lower likelihood that certain deferred tax assets of Italian subsidiaries can be recovered in future periods due to an expected reduction in taxable income generated in Italy.

The Group s consolidated tax rate decreased to 64.5% in 2013 compared to 70.2% in 2012, down 5.7 percentage points. This was mainly due to the recognition of gains which were non-taxable items for tax purposes or subject to a rate lower than the Group statutory tax rate. These gains were mainly recorded on the sale of a 28.57% interest in Eni East Africa SpA and the fair-value revaluation of Eni s interest in Artic Russia. The reported tax rate of 64.5% was higher than the Group statutory tax rate of 43%, which corresponds to the Italian tax rate for corporation profit, due to the fact the Group profit before taxation was mainly earned by the Group foreign subsidiaries in the Exploration and Production segment which are taxed at rates that are much higher than the Italian statutory tax rate.

Management also estimated the tax rate at approximately 66% excluding certain items such as divestment gains and asset impairments and other risk provisions. We expect that, absent any gains on divestment and other charges which we do not plan for, the Group tax rate in 2014 will be mainly in line with the underlying tax rate of 2013 as management forecasts that a large part of the Group taxable profit will be earned by the Exploration & Production segment. Looking forward, management believes that the Group tax rate might come a bit lower due to a projected increase in taxable profit reported by foreign subsidiaries in the Exploration & Production segment with a lower than average tax rate reflecting production start-ups and a progressive recovery in the profitability of the other Group business segments which tax rate is in line with the Italian statutory tax rate.

2012 compared to 2011. In 2012, income taxes amounted to euro 11,679 million, up by euro 1,776 million compared to 2011, or 17.9%, mainly reflecting higher income taxes currently payable by subsidiaries in the Exploration & Production segment operating outside Italy due to higher taxable profit and a write down of euro 1,030 million which was recorded at deferred tax assets of Italian subsidiaries.

The Group s consolidated tax rate increased compared to 2011, up from 55.7% to 70.2% (up 14.5 percentage points). This increase was due to:

(i) a write down of euro 1,030 million which was recognized to reflect a lower likelihood that certain deferred tax assets of Italian subsidiaries can be recovered in future periods due to an expected reduction in taxable income generated in Italy, and as Eni has lost the availability of Snam taxable profit against which Italian tax assets can be utilized following the deconsolidation of Snam;

(ii) a shift from profit earned by associates to increased taxable income reported by the Exploration & Production segment, subject to higher tax rates; and

(iii)

the significant amount of non-deductible charges (mainly the goodwill impairment of the European market cash generating unit).

These negatives were partly offset by the non-taxable gains which were recorded on the Galp interest and the fact that based on the accounting provided by IFRS 5, the Group taxable income from continuing operations benefited from Snam s margins on intercompany transactions which are deprived of any tax impact.

h) Non-controlling interest

2013 compared to 2012. Net loss pertaining to non-controlling interest was euro 201 million and concerned primarily Saipem SpA (euro 190 million).

2012 compared to 2011. Net profit pertaining to non-controlling interest was euro 889 million and concerned primarily Saipem SpA (euro 627 million).

Liquidity and capital resources

Eni s cash requirements for working capital, dividends to shareholders, capital expenditures and acquisitions over the past three years were financed primarily by a combination of funds generated from operations, borrowings and divestments of non-strategic assets. The Group continually monitors the balance between cash flow from operating activities and net expenditures targeting a sound and well-balanced financing structure.

The following table summarizes the Group cash flows and the principal components of Eni s change in cash and cash equivalent for the periods indicated.

	Year ended December 31,		
	2011	2012	2013
		(euro million)	
Net profit - continuing operations	**7,877**	**4,947**	**4,959**
Adjustments to reconcile net profit to net cash provided by operating activities:			
- amortization and depreciation charges, impairment losses and other non-monetary items	8,606	11,501	9,723
- net gains on disposal of assets	(1,176)	(875)	(3,770)
- dividends, interest, taxes and other changes	9,918	11,962	9,174
Changes in working capital related to operations	(1,696)	(3,281)	456
Dividends received, taxes paid, interest (paid) received during the period	(9,766)	(11,702)	(9,516)
Net cash provided by operating activities - continuing operations	**13,763**	**12,552**	**11,026**
Net cash provided by operating activities - discontinued operations	619	15	
Net cash provided by operating activities	**14,382**	**12,567**	**11,026**
Capital expenditures - continuing operations	**(11,909)**	**(12,805)**	**(12,800)**
Capital expenditures - discontinued operations	(1,529)	(756)	
Capital expenditures	**(13,438)**	**(13,561)**	**(12,800)**
Investments and purchases of consolidated subsidiaries and businesses	(360)	(569)	(317)
Disposals	1,912	6,025	6,360
Other cash flow related to investing activities (*)	668	(272)	(4,224)
Changes in short and long-term finance debt	1,104	5,814	1,715
Dividends paid and changes in non-controlling interests and reserves	(4,327)	(3,743)	(4,225)
Effect of changes in consolidation and exchange differences	10	(16)	(40)
Change in cash and cash equivalent for the year	**(49)**	**6,245**	**(2,505)**
Cash and cash equivalent at the beginning of the year (1)	1,549	1,691	7,936
Cash and cash equivalent at year end	1,500	7,936	5,431

(1) The 2012 opening balance was restated in accordance with IFRS 10 and IFRS 11.

(*) Net cash used in investing activities included investments in certain financial assets (mainly bank deposits) to absorb temporary surpluses of cash or as part of our ordinary management of financing activities. Due to their nature and the circumstance that they are very liquid, these financial assets are netted against finance debt in determining net borrowings. In addition, from 2013 the Company has been maintaining a cash reserve made by very liquid investments (mainly sovereign and corporate securities which management has selected based on their creditworthiness) by investing part of the proceeds from the disposition plan which has been made in 2012 and 2013 and the proceeds from the reimbursement of certain financing receivables towards the former subsidiary Snam which was divested at the end of 2012. These investments are held-for-trading financial assets. For more information on their composition see "Item 18 note 8 Financial assets held for trading of the Notes to the Consolidated Financial Statements". For the definition of net borrowings, see "Financial Condition" below. Cash flows of such investments were as follows:

(euro million)	2011	2012	2013
Financing investments:			
- securities	(21)		(5,029)
- financing receivables	(26)	(1,172)	(105)
	(47)	**(1,172)**	**(5,134)**
Disposal of financing investments:			
- securities	71	6	28
- financing receivables	17	1,087	1,125
	88	**1,093**	**1,153**
Net cash flows from financing activities	**41**	**(79)**	**(3,981)**

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The table below sets forth the principal components of Eni s change in net borrowings[1] for the periods indicated.

	Year ended December 31,		
	2011	2012	2013
	(euro million)		
Net cash provided by operating activities	**14,382**	**12,567**	**11,026**
Capital expenditures	(13,438)	(13,561)	(12,800)
Acquisitions of investments and businesses	(360)	(569)	(317)
Disposals	1,912	6,025	6,360
Other cash flow related to capital expenditures, investments and divestments	627	(193)	(243)
Net borrowings [1] of acquired companies		(2)	(21)
Net borrowings [1] of divested companies	(192)	12,446	(23)
Exchange differences on net borrowings and other changes	(517)	(345)	349
Dividends paid and changes in minority interest and reserves	(4,327)	(3,743)	(4,225)
Change in net borrowings [1]	**(1,913)**	**12,625**	**106**
Net borrowings [1] [2] at the beginning of the year	26,119	27,694	15,069
Net borrowings [1] at year end	28,032	15,069	14,963

(1) Net borrowings is a non-GAAP financial measure. For a discussion of the usefulness of net borrowings and its reconciliation with the most directly comparable GAAP financial measures see "Financial Condition" below.
(2) The 2012 opening balance was restated in accordance with IFRS 10 and IFRS 11.

Analysis of certain components of Eni s change in net borrowings

In 2013, adjustments to reconcile net profit from continuing operations to net cash provided by operating activities from continuing operations mainly related to non-monetary charges and gains, which primarily regarded depreciation, depletion, amortization and impairment charges of tangible and intangible assets (euro 11,821 million) net of the fair value revaluation of Eni s interest in Artic Russia amounting to euro 1,682 million and other changes. Adjustments to net profit also included gains on disposals (euro 3,770 million) mainly relating to the Mozambique transaction, income taxes (euro 9,005 million) and interest expenses (euro 711 million) net of the dividends and interest income accrued in the year as opposed to amounts actually paid.

In 2012, adjustments to reconcile net profit from continuing operations to net cash provided by operating activities from continuing operations mainly related to non-monetary charges and gains, which primarily regarded depreciation, depletion, amortization and impairment charges of tangible and intangible assets (euro 13,617 million). Adjustments to net profit from continuing operations also included gains on disposals (euro 875 million), while the difference between accrued amounts of income taxes, interest expenses and other items as opposed to amounts actually disbursed was immaterial.

a) Changes in working capital related to operations

In 2013, changes in working capital generated cash flows amounting to a positive euro 456 million as a result of: (i) decreasing gas and petroleum products inventories (a positive euro 350 million) as a result of destocking oil and products inventories, the effect of which were partly offset by higher contract work in progress in the Engineering & Construction segment albeit of a lower magnitude than in 2012; and (ii) a positive balance of other current assets and liabilities (up by euro 723 million) which mainly reflected a net positive inflow in the Gas & Power segment due to the collection of pre-paid volumes of gas under take-or-pay contracts and the collection of receivables from supplied long term customers which were partly offset by payments made to long term, gas suppliers for the lower volumes of gas collected in 2012 with respect to minimum take obligations. Also the Engineering & Construction segment benefited from cash inflows from contract advances; the effects of which were partly offset by net cash absorbed by the balance between trade receivables and payables (down by euro 676 million) due to a deteriorated credit environment, particularly in the Gas & Power segment, which caused a slowdown in the collection of trading receivables; and increased exposure to joint venture partners in the Exploration & Production segment in the execution of capital projects and due to under-lifting with respect to the Company s own share of production.

In 2012, changes in working capital absorbed cash flows amounting to a negative euro 3,281 million as a result of: (i) increasing inventories (up euro 1,402 million) mainly related to higher contract work in progress in the Engineering & Construction segment; (ii) an increased balance between trade payables and receivables (up by euro 1,147 million)

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also resulting from a higher volume of trade receivables which were mainly recorded in the Gas & Power segment; and (iii) cash prepayments amounting to approximately euro 500 million made to the Company s gas suppliers which were recorded on the take-or-pay position accrued in 2012 including payment of outstanding receivables at the beginning of the year. For further details on that asset see Item 18 Note 21 Other non-current receivables of the Notes to the Consolidated Financial Statements .

b) Investing activities

	Year ended December 31,		
	2011	**2012**	**2013**
		(euro million)	
Exploration & Production	9,435	10,307	10,475
Gas & Power	192	213	229
Refining & Marketing	866	898	672
Chemicals	216	172	314
Engineering & Construction	1,090	1,011	902
Other activities	10	14	21
Corporate and financial companies	128	152	190
Impact of unrealized intragroup profit elimination	(28)	38	(3)
Capital expenditures - continuing operations	**11,909**	**12,805**	**12,800**
Capital expenditures - discontinued operations	1,529	756	
Capital expenditures	**13,438**	**13,561**	**12,800**
Acquisition of investments and businesses	**360**	**569**	**317**
	13,798	**14,130**	**13,117**
Disposals	**(1,912)**	**(6,025)**	**(6,360)**

Capital expenditures totaled euro 12,800 million and euro 13,561 million, respectively in 2013 and in 2012.

For a discussion of capital expenditures by business segment and a description of year-on-year changes see below "Capital expenditures by segment".

Acquisition of investments and businesses totaled euro 317 million in 2013 and euro 569 million in 2012.

In 2013, disposals amounted to euro 6,360 million and mainly related to: (i) the divestment of a 28.57% interest in Eni East Africa, currently retaining an interest of 70% in the Area 4 mineral property in Mozambique to China National Petroleum Corp (euro 3,386 million), (ii) the divestment of the 11.69% interest in the share capital of Snam (euro 1,459 million), (iii) the sale of a 8.19% interest in the share capital of Galp (euro 830 million); and (iv) other non strategic assets in the Exploration & Production segment.

In 2012, disposals amounted to euro 6,025 million and mainly related to: the divestment of 30% interest less one share in Snam to Cassa Depositi e Prestiti (euro 3,517 million), two trances of the interest in Galp for an overall amount of euro 963 million (a 5% interest sold to Amorim BV and a 4% sold through an accelerated book-building procedure), a 10% interest in the Karachaganak field (euro 500 million), a 1.43% interest in the Gassled JV, a network of gas pipelines and terminals for natural gas transportation (euro 130 million) and other non-strategic assets in the Exploration & Production segment (euro 565 million). The proceeds on the divestment of an interest of 5% in Snam before loss of control to institutional investors (euro 612 million) were recognized as an equity transaction.

c) Dividends paid and changes in non-controlling interests and reserves

In 2013, dividends paid and changes in non-controlling interests and reserves (euro 4,225 million) mainly related to: (i) cash dividends to Eni shareholders (euro 3,949 million, which euro 1,993 million relating to 2013 interim dividend and euro 1,956 million to the balance dividend for fiscal year 2012 to Eni s shareholders); and (ii) the distribution of dividends to non-controlling interests by Saipem SpA (euro 170 million) and other consolidated subsidiaries (euro 80 million).

In 2012, dividends paid and changes in non-controlling interests and reserves (euro 3,743 million) mainly related to: (i) cash dividends to Eni shareholders (euro 3,840 million, which euro 1,956 million relating to 2012 interim dividend and euro 1,884 million to the balance dividend for fiscal year 2011 to Eni s shareholders); and (ii) the distribution of dividends to non-controlling interests by Snam SpA and Saipem SpA (euro 486 million) and other consolidated subsidiaries (euro 50 million). Those outflows were partly absorbed by an equity transaction involving 5% of the share capital of Snam which was divested to third-party investors before loss of control for euro 612 million.

Financial condition

Management assesses the Group capital structure and capital condition by tracking net borrowings, which is a non-GAAP financial measure. Eni calculates net borrowings as total finance debt (short-term and long-term debt) derived from its Consolidated Financial Statements prepared in accordance with IFRS less: cash, cash equivalents and certain highly liquid investments not related to operations including, among others, non-operating financing receivables and securities not related to operations. From 2013 the Company has been maintaining a cash reserve comprised of very liquid investments (mainly sovereign and corporate securities which management has selected based on their creditworthiness) by investing part of the proceeds from the disposition plan carried out in 2012 and 2013 and the proceeds from the reimbursement of certain financing receivables towards the former subsidiary Snam which was divested at the end of 2012. Those securities amounted to euro 5,037 million as of end of 2013 and were accounted as mark-to-market financial instruments. For further information see "Item 18 note 8 Financial assets held for trading of the Notes to the Consolidated Financial Statements". Non-operating financing receivables consist mainly of deposits with banks and other financing institutions and deposits in escrow.

Management believes that net borrowings is a useful measure of Eni s financial condition as it provides insight about the soundness of Eni s capital structure and the ways in which Eni s operating assets are financed. In addition, management utilizes the ratio of net borrowings to total shareholders equity including non-controlling interest (leverage) to assess Eni s capital structure, to analyze whether the ratio between finance debt and shareholders equity is well balanced according to industry standards and to track management s short-term and medium-term targets. Management continuously monitors trends in net borrowings and trends in leverage in order to optimize the use of internally-generated funds versus funds from third parties. The measure calculated in accordance with IFRS that is most directly comparable to net borrowings is total debt (short-term and long-term debt). The most directly comparable measure, derived from IFRS reported amounts, to leverage is the ratio of total debt to shareholders equity (including non-controlling interest). Eni s presentation and calculation of net borrowings and leverage may not be comparable to that of other companies.

The tables below set forth the calculations of net borrowings and leverage for the periods indicated and their reconciliation to the most directly comparable GAAP measure.

	As of December 31,								
	2011			2012			2013		
	Short-term	Long-term	Total	Short-term	Long-term	Total	Short-term	Long-term	Total
	(euro million)								
Total debt (short-term and long-term debt)	**6,495**	**23,102**	**29,597**	**5,047**	**19,145**	**24,192**	**4,685**	**20,875**	**25,560**
Cash and cash equivalents	(1,500)		(1,500)	(7,936)		(7,936)	(5,431)		(5,431)

Securities held for trading and other securities held for non-operating purposes	(37)		(37)	(36)		(36)	(5,037)		(5,037)
Non-operating financing receivables	(28)		(28)	(1,151)		(1,151)	(129)		(129)
Net borrowings	**4,930**	**23,102**	**28,032**	**(4,076)**	**19,145**	**15,069**	**(5,912)**	**20,875**	**14,963**

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		As of December 31,		
		2011	2012	2013
Shareholders equity including non-controlling interest as per Eni s Consolidated Financial Statements prepared in accordance with IFRS	(euro million)	**60,393**	**62,417**	**61,049**
Ratio of total debt to total shareholders equity including non-controlling interest		*0.49*	*0.39*	*0.42*
Less: ratio of cash, cash equivalents and certain liquid investments not related to operations to total shareholders equity including non-controlling interest		*(0.03)*	*(0.15)*	*(0.17)*
Ratio of net borrowing to total shareholders equity including non-controlling interest (leverage)		*0.46*	*0.24*	*0.25*

In 2013, net borrowings amounted to euro 14,963 million, representing a euro 106 million decrease from 2012 as a result of net cash provided by operating activities of continuing operations (euro 11,026 million) and proceeds from disposals of euro 6,360 million which funded cash outflows relating to capital expenditures totaling euro 12,800 million and investments (euro 317 million) and dividend payments and other changes amounting to euro 4,225 million, and currency translation differences which amounted to a positive euro 630 million.

The Group leverage was 0.25 at December 31, 2013 reporting a small increase from 0.24 as of end of 2012.

Total equity decreased by euro 1,368 million from December 31, 2012. This was due to comprehensive income for the year (euro 2,909 million) as a result of net profit (euro 4,959 million), which was partly offset by foreign currency translation differences (euro 1,872 million) in translating to euro amounts the net equity of subsidiaries whose functional currency is the U.S. dollar due to the euro revaluation in exchange rates recorded at year end (up by 4.5% due to the exchange rate recorded on December 31, 2013 at 1 euro = 1.379 US$ compared to 1 euro = 1.319 US$ at December 31, 2012). This addition to equity was almost completely offset by dividend payments to Eni s shareholders and other changes for euro 4,225 million.

Total debt of euro 25,560 million consisted of euro 4,685 million of short-term debt (including the portion of long term debt due within twelve months equal to euro 2,132 million) and euro 20,875 million of long-term debt.

Total debt included ordinary bonds for euro 18,151 million (including accrued interest and discount on issuance). Bonds maturing in the next 18 months amounted to euro 3,493 million (including accrued interest and discount). Bonds issued in 2013 amounted to euro 3,096 million (including accrued interest and discount). Total debt was denominated in the following currencies: euro (90%), U.S. dollar (7%), pound sterling (2%) and 1% in other currencies.

In 2012, net borrowings amounted to euro 15,069 million, representing a euro 12,963 million decrease from 2011. This decrease was mainly due to the divestment of a 30% interest in Snam to Cassa Depositi e Prestiti (euro 3,517 million) and, following the loss of control in this entity, the deconsolidation of Snam net borrowings of euro 12,448 million, which entered finance arrangements with third-party lenders to reimburse intercompany loans.

Net cash provided by operating activities (euro 12,567 million) and proceeds from disposals of euro 6,025 million funded cash outflows relating to capital expenditures totaling euro 13,561 million and investments (euro 569 million) relating to the acquisition of Nuon in Belgium and joint venture projects, as well as dividend payments to shareholders.

The Group leverage was 0.24 at December 31, 2012 declining from 0.46 as of end of 2011 due to the lower level of net borrowings.

Capital expenditures by segment

Exploration & Production. In 2013, capital expenditures of the Exploration & Production segment amounted to euro 10,475 million, representing an increase of euro 168 million, or 1.6%, from 2012 mainly due to the development of oil and gas reserves (euro 8,580 million). Significant expenditures were directed mainly outside Italy, in particular Norway, the United States, Angola, Congo, Nigeria, Kazakhstan, Egypt and the United Kingdom. Development expenditures in Italy concerned the well drilling program and facility upgrading in Val d Agri, as well as sidetrack and infilling activities in mature fields. About 98% of exploration expenditures that amounted to euro 1,850 million were directed outside Italy, in particular in Mozambique, Norway, Congo, Togo, Nigeria, the United States and Angola as well as the acquisition of new licenses in the Republic of Cyprus and in Vietnam.

In 2012, capital expenditures of the Exploration & Production segment amounted to euro 10,307 million, representing an increase of euro 872 million, or 9.2%, from 2011 mainly due to the development of oil and gas reserves (euro 8,304 million). Significant expenditures were directed mainly outside Italy, in particular Norway, the United

States, Congo, Kazakhstan, Angola and Algeria. Development expenditures in Italy concerned the well drilling program and facility upgrading in Val d Agri, as well as sidetrack and infilling activities in mature fields. About 98% of exploration expenditures that amounted to euro 1,850 million were directed outside Italy, in particular in Mozambique, Liberia, Ghana, Indonesia, Nigeria, Angola and Australia.

Gas & Power. In 2013, capital expenditures in the Gas & Power segment totaled euro 229 million and mainly related to initiatives to improve flexibility of the combined-cycle power plants (euro 119 million) and to develop the gas marketing activity (euro 87 million).

In 2012, capital expenditures in the Gas & Power segment totaled euro 213 million and mainly related to initiatives to improve flexibility of the combined-cycle power plants (euro 123 million) and to develop the gas marketing activity (euro 77 million).

Refining & Marketing. In 2013, capital expenditures in the Refining & Marketing segment amounted to euro 672 million and regarded mainly: (i) refining, supply and logistics with projects designed to improve the conversion rate and flexibility of refineries (euro 462 million), in particular at the Sannazzaro refinery; and (ii) upgrading and rebranding of the refined product retail network (euro 210 million).

In 2012, capital expenditures in the Refining & Marketing segment amounted to euro 898 million and regarded mainly: (i) refining, supply and logistics with projects designed to improve the conversion rate and flexibility of refineries (euro 639 million), in particular at the Sannazzaro refinery; and (ii) upgrading and rebranding of the refined product retail network (euro 259 million).

Chemicals. In 2013, capital expenditures in the Chemical segment amounted to euro 314 million and regarded mainly: (i) improvement of plants efficiency (euro 170 million); (ii) upkeeping of plants (euro 66 million); (iii) environmental protection, safety and environmental regulation (euro 52 million); and (iv) maintenance and savings (euro 14 million).

In 2012, capital expenditures in the Chemical segment amounted to euro 172 million and regarded mainly: (i) plant upgrades (euro 53 million) in particular in Ravenna; (ii) energy efficiency (euro 41 million), mainly related to energy savings projects aimed at reducing CO_2 emissions; (iii) environmental protection, safety and environmental regulation (euro 38 million), relating primarily to the optimization of discharge water treatment; and (iv) upkeeping of plants (euro 25 million).

Engineering & Construction. In 2013, capital expenditures in the Engineering & Construction segment (euro 902 million) mainly regarded: (i) completion of the preparation work for a new pipelayer, in continuation of the construction activity of a new base in Brazil, as well as maintenance and upgrading of existing assets in the Offshore Engineering & Construction business; (ii) acquisition of equipment and facilities for the base in Canada, as well as maintenance of the asset base in the Onshore Engineering & Construction business; (iii) upgrading of the works on the semi-submersible rig Scarabeo 5 and Scarabeo 7 as well as jack-up Perro Negro 3, in the Offshore Drilling business unit; and (iv) purchase of materials and equipment and planned upkeep of the current asset base in the Onshore Drilling business.

In 2012, capital expenditures in the Engineering & Construction segment (euro 1,011 million) mainly regarded: (i) the construction of a new pipelayer, the construction of a new fabrication yard in Indonesia, the construction of a new fabrication yard in Brazil and upkeep works in the Offshore Engineering & Construction business; (ii) activities for the completion of the construction of the Scarabeo 8 and the upgrading of the Scarabeo 6 to make it capable of drilling up to 1,100 meters of water; (iii) realization/development of operating structures in the Offshore Drilling business unit; and (iv) purchase of materials and equipment and planned upkeep of the current asset base in the Onshore Drilling business.

Recent developments

The table below sets forth certain indicators of the trading environment for the periods indicated:

	Three months ended March 31,	
	2013	2014
Average price of Brent dated crude oil in U.S. dollars (1)	112.60	108.21
Average price of Brent dated crude oil in euro (2)	84.66	78.96
Average EUR/USD exchange rate (3)	1.330	1.371
Average European refining margin in U.S. dollars (4)	3.92	1.70
EURIBOR - three month euro rate % (3)	0.2	0.3

(1) Price per barrel. Source: Platt s Oilgram.
(2) Price per barrel. Source: Eni s calculations based on Platt s Oilgram data for Brent prices and the EUR/USD exchange rate reported by the European Central Bank (ECB).
(3) Source: ECB.
(4) Price per barrel. FOB Mediterranean Brent dated crude oil. Source: Eni calculations based on Platt s Oilgram data.

Significant transactions

The Company s Annual General Shareholders Meeting scheduled on May 8, 2014, is due to approve the full year dividend proposal of euro 1.10 per share. Eni expects to pay the balance of the dividend for fiscal year 2013 amounting to euro 0.55 per share in May 2014. The total cash out is estimated at euro 1.99 billion.

On January 15, 2014, the divestment of Eni s interest in Artic Russia was closed and the Company collected proceeds of euro 2.2 billion.

On March 28, 2014, through an accelerated book-building procedure aimed at institutional investors, Eni sold approximately 7% of the share capital of Galp Energia SGPS SA at the price of euro 12.10 per share, for a total consideration of euro 702.4 million. Following this transaction, Eni retains a 9% interest in Galp, of which 8% underlying the approximately euro 1,028 million exchangeable bond due on November 30, 2015.

On March 31, 2014, Eni and Statoil have signed final agreement on the revision of the long-term gas supply contract currently in force between the two parties. The revision is reflecting changed fundamentals in the gas sector and will determine a positive effect in 2014 profit. The final agreement, which follows the Heads of Agreement signed on February 27, 2014, implies the end of the arbitration proceedings previously initiated by Eni.

Management s expectations of operations

The 2014 outlook features a moderate strengthening in the global economic recovery. However a number of uncertainties affect this outlook due to weak growth prospects in the Euro-zone and risks concerning the emerging economies. Crude oil prices are forecast on a higher trend than our long-term expectations of 90 $/BBL driven by geopolitical factors and the resulting operational issues in a few important producing countries against the backdrop of well supplied global markets. Management expects that the trading environment will remain challenging in the other Company s businesses. We expect continuing weak conditions in the European gas distribution, refining and marketing of fuels and chemical products, where we do not anticipate any meaningful improvement in demand, while competition, excess supplies and overcapacity will continue to weigh on selling margins of energy commodities. In this scenario, management reaffirms its commitment to restore profitability and preserve cash generation at the Company s loss making businesses leveraging on cost cuts and continuing renegotiation of long-term gas supply contracts, capacity restructuring and reconversion and product and marketing innovation.

Exploration & Production

We expect the outlook for the production of liquids and natural gas to be uncertain in 2014 due to our belief that political and social instability in the Company s key producing countries, Libya and Nigeria, may continue. Management has prudently assumed that the Company s production levels in those countries will remain unchanged from the volumes reported in 2013 at least for a couple of years. In addition, management is assuming marginal production volumes at the Kashagan field which has been shut down due to a technical issue in the fourth quarter of 2013. See "Item 4 Exploration & Production". Finally, year-on-year comparison in 2014 will be affected by the divestment of Eni s stake in the joint venture Artic Russia. In 2013, our equity share of the production of Artic Russia was 29 KBOE/d. Excluding the effect of this divestment and factoring in the assumptions about the projected production levels in Libya and Nigeria and at the Kashagan field, management expects flat production in 2014 compared to 2013.

According to management s plans, production growth will resume in the coming years as the Company is targeting an annual growth rate of 3% on average over the next 2014-2017 four-year period, based on an expectation of a gradual decrease in oil prices from 104 $/BBL in 2014 to 90 $/BBL in 2017. Oil price assumptions are particularly significant when it comes to assessing the Company s future production performance considering the entitlement mechanism under Eni s PSAs and similar contractual schemes. The Company estimates that production entitlements in its PSAs will decrease on average by approximately 1,000 BBL/d for each $1 increase in oil prices compared to current Eni s assumptions for oil prices. Our production growth target factors in an average decline rate lower than 5% per annum at our currently producing fields throughout the plan period. To achieve that decline rate, we plan to carry out effective reservoir management and continued production optimization activities.

The main driver of future growth will be the start-up of 26 major fields which we estimate to add more than 500 KBOE/d of new production by the end of the plan period. These new barrels will fuel growth and replace mature field declines. We have a good level of visibility on those new projects as we have already sanctioned a number equivalent to approximately 70% of projected volume additions. The bulk of these projects will be concentrated offshore Angola, Indonesia, Norway, the Gulf of Mexico, Ghana and Congo.

Management will focus on delivering the planned projects on time and on budget. We acknowledge that most of our projects are complex due to scale and reach of operations, environmentally-sensitive or remote locations, harsh external conditions, industry limits and other considerations including the risk factors described in Item 3. These constraints and factors might cause delays and cost overruns. Furthermore, we have experienced delays and cost overruns at certain projects which were caused by poor execution by our EPC contractors. We plan to mitigate those risks in the future by continuing deployment of our capabilities and operational excellence and managing the industry constraints by means of: (i) in-sourcing critical engineering and project management activities; (ii) increasing direct control and governance on construction activities; (iii) deploying our employees and competences to manage hook-up and commissioning; and (iv) entering into framework agreements with major suppliers, using standardized specifications to speed up pre-award process for critical equipment and plants and increasing focus on supply chain programming to optimize order flows. Currently we believe that our pool of projects as a whole is running in line with our time and cost estimates.

Management expects that a number of factors will drive cost increase in the Exploration & Production operations over future years. Those factors include: (i) the growing complexity and scale of the Company s planned development projects due to the circumstance that several planned or ongoing projects will be executed offshore or in remote/hostile environments where the Company has been experiencing above-average cost increases; (ii) increasing investing activities that are necessary to support production plateaus at existing fields and counteract natural depletion; and (iii) steady trends in costs for purchasing upstream goods and services. Due to those trends, operating costs and depreciation and amortization charges might trend higher in future years. We believe that a number of actions will help the Company absorb inflationary and cost pressures including tighter cost control, operation efficiency and increasing exposure to large fields which enable the Company to benefit from economies due to scale of operations. Management also plans to increase the share of operated production in the Company s portfolio. Project operatorship enables the Company to better schedule and control project execution, expenditures and timely achievement of project milestones. In addition, the Company plans to seek cost efficiencies due to greater deployment of proprietary technologies designed to maximize the rate of hydrocarbon recovery from reservoirs and reduce drilling costs as well as continuing operational improvement.

We intend to grow profitably. We will seek to increase the profit per barrel in the next four-year plan leveraging on cost control, the delivery of new projects on time and on budget and higher productivity at our existing producing fields which will be driven by actions to prolong the field lives and fight depletion and reduced facility downtime. The profitability per barrel will also benefit from the fact that most of the new projects scheduled to start in the next four years have been derived from our exploration activity. We believe that our discovery costs have been very competitive; this will contribute to lower the break-even price of our projects.

The better profitability per barrel is expected to help the Company improve the cash generation in its Exploration & Production business and increase the surplus of cash generated from operating activities over capital expenditure in each of the next four years. The latter will reflect our increased focus on capital discipline whereby we plan to achieve the same volume additions as in the previous four-year plan spending 5% less thanks to a better schedule of the development phases of our long-plateau projects. We project over the next four years a capital spending budget of approximately euro 38 billion to develop reserves compared to euro 41 billion in the previous plan.

Our exploration activity will require some euro 1.4 billion per year until 2017. We plan to execute exploration projects in new areas mainly offshore the Russian and the Norwegian section of the Barents Sea, Cyprus, the pre-sale layers of West Africa and Kenya, Vietnam, Indonesia and Australia. These are little-explored areas where the risks of dry hole are high. These risks will be counterbalanced by an equivalent number of low-risk exploration projects which will conducted mainly in the vicinity of already producing fields or in areas with proved reserves.

Gas & Power

We expect a weak outlook for natural gas sales and profitability due to our belief that structural headwinds in the industry will continue as we forecast demand stagnation, oversupplies and strong competition. Management does not expect any improvements in this scenario in the next four-year plan. Management expects gas sales to be flat to down over the next four years and gas prices to continue falling.

We believe that weaker-than-anticipated demand growth over the foreseeable future which is expected to be dragged down by macroeconomic uncertainties, the current downturn in the thermoelectric sector to continue and rising competitive pressures which are expected to be fuelled by ongoing oversupplies in the European market will reduce sales opportunities and fuel pricing competition, also considering the constraints of the long-term supply contracts with take-or-pay clauses. The absolute level of gas consumption in Italy and Europe is far below the levels recorded in 2008, down by approximately 20% and 10%, respectively, and we believe that there are no signs of any significant rebound in the foreseeable future. This trend will exacerbate the current oversupply situation in Europe and pricing pressure on gas sales. Furthermore, we expect that minimum collection obligations in connection with take-or-pay, long-term gas supply contracts and the necessity to minimize the associated financial exposure will force gas operators to compete aggressively on pricing in consideration of lower selling opportunities, with negative effects on selling prices and profitability. Unit margins are expected to remain under pressure due to depressed spot prices at continental hubs which have become the contractual benchmark in selling formulas in our European markets and, more recently, also in Italy. In addition, as long as the cost of gas supplies to the Group remains indexed to oil prices, the Company will be exposed to the risk of rising oil prices.

In Italy we expect that gas prices and margins in the wholesale market will continue to fall due to a number of negative catalysts including competitive pressure, an ongoing shift to index selling prices to hub benchmarks at large customer segments and the current level of minimum take volumes of Italian operators which are well above the absolute dimension of the Italian market dimension. In addition, we expect that the indexation of selling prices to hub benchmark will be reflected also in our long-term selling contracts. In the retail market, we expect that tariffs and margin will come down due to new indexation measures which were implemented by the Italian administration in 2013 to cut the gas tariffs to residential customers. See also the other risk factors described in Item 3. Finally, our margins in the production of electricity at our gas-fired stations have significantly deteriorated throughout 2013 due to the increasing pressure of cheaper electricity from coal and renewables and there are no signs that this trend will reverse in 2014 and beyond. These drivers will negatively impact the profitability at our Italian operations.

Against this scenario the Company has set the following priorities: preserve the operating cash flow during the worst phase of the downturn which is expected to continue well into 2014 and recover sustainable, long-term profitability and positive cash in subsequent years as a result of contract renegotiations, focus on value-added segments and cost streamlining.

The main driver to recover profitability in the Company s gas marketing business is the renegotiation of pricing and other conditions of our supply contracts. Take-or-pay supply contracts include revisions clauses allowing the counterparties to renegotiate the economic terms and other conditions periodically, in relation to ongoing changes in the gas scenario. We will seek to renegotiate our long-term supply contracts going and to align supply costs to the selling prices of spot markets based on the contractual principle which states a fair sharing of the economic benefits between the counterparties. In 2013, we finalized a round of renegotiations whereby we renewed pricing and volume terms of about 85% of our gas supplies under long-term contracts. However, the benefits associated with past renegotiations were not enough to fully align our cost position with selling benchmarks which depend on spot quotations of gas at continental or Italian hubs. Therefore, management is seeking to finalize a new round of renegotiations targeting a better alignment of the cost of gas to the Company with the selling benchmarks. This can be achieved by increasing the exposure to spot gas in the indexation mechanism in the pricing formulas of gas supplied. We expect to complete the planned renegotiations at the beginning of 2016. Once we have completed contract renegotiations in accordance to our plans, we will be in better position to seek to regain competitiveness and to preserve our profitability.

However, management warns that the outcome of those renegotiations is uncertain in respect of both the amount of the economic benefits that will ultimately be achieved and the timing of recognition in profit. Furthermore in case counterparties fail to agree to revise contractual terms, ongoing supply contracts provide a chance to each of them to recur to an arbitration proceeding to define a commercial transaction. This potentially adds to the level of uncertainty surrounding the outcome of those renegotiations. Considering also ongoing price renegotiations with Eni long-term customers, future results of the Gas Marketing activities are subject to increasing volatility and unpredictability.

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Difficult market conditions in the European gas sector are expected to continue over the entire plan period. Looking beyond, there is still little visibility about future developments in the European gas sector. Management expects that a number of positive trends might eventually help rebalance the European market, including macroeconomic stability and a renewed focus by European agencies on the role of gas in electricity production, also considering the lower level of GHG emissions of gas-fired electricity compared to the use of coal in firing power plants. Possible reductions in the role of nuclear energy in crucial Countries like Japan, Taiwan and in Europe might support long-term trends in gas demand. In addition, we foresee continuing growing energy needs from the developing economies of China, India and other emerging countries in East Asia, the Middle East and South America that will be covered by worldwide LNG streams. On the supply side, production rates at European fields are projected to decline, thus increasing the need for gas import requirements. However, there exist a number of downside risks to this outlook, particularly the possible long-term impacts on gas demand associated with the current economic downturn, an ongoing shift to renewable sources in the production of electricity and home heating and the other risk factors described in Item 3. Also it is apparent that the United States Government is speeding up the authorization process to better exploit the Country s large reserve base of shale gas by giving permission to reconvert existing re-gasification plants into LNG export facilities. Finally, new upstream projects might be started up in the long run adding to global LNG supplies (particularly the projects to develop gas reserves in Mozambique and a number of projects in the Pacific Area).

In addition to contract renegotiation, the Company intends to seek to recover profitability in its gas marketing operations by focusing on market segments where we believe it is possible to earn a profit. As part of this plan, we intend to strengthen our role as a global player in LNG trading where we have obtained an acceptable profitability so far. We intend to increase traded volumes of LNG to Asia and in the long run we will leverage integration with our upstream operations by marketing equity gas, particularly with the start of the gas projects in Mozambique. We left behind us the traditional role of gas intermediary with our large industrial and thermoelectric customers across Europe and will seek to earn a profit on wholesale gas sales by leveraging on the Company s multiple presence across various markets and expertise in delivering innovative and tailor-made offering structures to best suit customers needs by providing complex pricing formulas and flexibility in volumes collection (see Item 4 Gas & Power). The second leg of the Company s marketing effort will address retail customers across Europe with a view to enhancing the existing customer base. The drivers to achieve this will be a strategy of customer retention centered on brand identity, the administrative advantages of the dual offer of gas and electricity and a competitive cost to serve; a wide range of sale channels and continuing innovation in processes, promotion and customer care and post-sale assistance. We believe that bundling a wide range of valuable services with the selling of the commodity will underpin the profitability of our retail operations considering that the regulatory modifications to the indexation of the raw material cost have substantially flatten the margin on the commodity. Finally, the Gas & Power segment will continue to benefit from the stable profit stream coming from the semi-regulated international transport activity. Management will also seek to improve profitability by means of cost efficiencies particularly in logistic, streamlining business support activities and reducing marketing and general and administrative costs. In addition, the Company intends to capture margins improvements by means of trading activities by entering derivative contracts both in the commodity and the financial trading venues in order to capture possible favorable trends in market prices, within the limits set by internal policies and guidelines that define the maximum tolerable level of market risk. As part of this strategy, the Company intends to improve results of operations by effectively managing the flexibilities associated with the Company s assets (gas supply contracts, transportation rights). This can be achieved through strategies of asset-backed trading by entering into derivative contracts to leverage on commodity price volatility, the risks of which might be absorbed in part or entirely by the natural hedge granted by the asset availability. This activity may lead to gain as well as loss the amount which could be significant. For further information on the market risk and how the Company manages it see Item 11 Quantitative and Qualitative Disclosures about Market Risk .

Based on the above outlined trends and industrial actions, management believes that the profitability in the Company s gas marketing business will gradually recover along the plan period, however the visibility into future results of operations is constrained by the ongoing volatility in marketing margins. Our profitability outlook factors in the expected benefits of ongoing renegotiations at the Company long-term supply contracts which the Company is seeking to finalize during the plan period, as well as other circumstances subject to risks and uncertainties described in Item 3.

Management believes that the weak industry outlook adversely affected by declining demand and large gas availability on the marketplace, the possible evolution of sector-specific regulation and strong competitive pressures represent risk factors to the Company s ability to fulfill its minimum take obligations associated with its long-term supply contracts. From the beginning of the downturn in the European gas market to date, Eni has incurred the take-or-pay clause as the Company collected lower volumes than its minimum take obligations accumulating deferred costs for an amount of euro 1.9 billion (net of amounts of volume make-up) paying the associated cash advances to its gas suppliers. Considering the Company s outlook for its sales volumes which are expected to be flat to down in the next four years, management believes the Company will be exposed to the risk of the incurrence of the take-or-pay clause in the plan period. Management intends to adopt the necessary initiatives to mitigate the financial risk related to take-or-pay obligations mainly in the domestic market where the expected volume of demand is lower in comparison with the minimum contracted supplies which Eni and other Italian gas importers are obliged to fulfill. The initiatives to mitigate the take-or-pay risk include the benefits expected from contract renegotiations which may temporarily reduce the annual minimum take, and provide more flexible collecting conditions such as changes in the delivery point or the possibility to replace supplies via pipeline with equivalent volumes of LNG.

These projections could be subject to the risks of further contraction in demand or the total addressable market. As to the deferred costs stated in the balance sheet amounting to euro 1.9 billion, based on management s outlook for gas demand and offer in Europe, and projections for sales volumes and unit margins in future years, the Company believes that the pre-paid volumes of gas due to the incurrence of the take-or-pay clause will be collected in the long term in accordance with contractual terms thus recovering the cash advances paid to suppliers. For more information see the specific risk paragraph in "Item 3 Risk factors".

For a discussion of certain risks relating to the impact of the evolution of Italian regulation of the natural gas sector on Eni s take-or-pay contracts see "Item 3 Risk factors Natural gas market".

Refining & Marketing

Management expects that the trading environment will show limited improvement throughout the four years covered by the industrial plan. This business segment will continue facing a challenging refining outlook due to structural headwinds in the industry which will continue to be affected by an anticipated weak demand, excess capacity, rising competitive pressure from imported product streams from Asia, Russia and possibly the United States, as well as risks of further margin pressure in case of upward trends in oil-linked raw material costs. As a result of those trends, we expect refining margins to remain at unprofitable levels in the foreseeable future. Furthermore, compressed differentials between heavy and light crudes will continue eroding Eni s advantage of having complex refining capacity in place.

In the refining business Eni will seek to mitigate the expected impacts of a negative scenario by primarily reducing refinery capacity. We are targeting a 22% capacity cut which we plan to accomplish by fully reconverting the Venice refinery into a bio-refinery which will reduce our exposure to the commodity risk and by shutting down unprofitable production lines at other refineries, mainly in the production of gasoline. We expect to invest approximately euro 0.6 billion for the conversion of Venice site and the reengineering of Gela in a diesel-only plant. We have defined other courses of actions which will provide for: (i) optimization of plant set-up and logistics operations by means of higher flexibility and process integration; (ii) cost efficiencies to be achieved by measures on labor, maintenance and other plant expenses and energy savings; (iii) selective capital expenditures mainly aimed at upgrading conversion capacity and improving asset integrity. In particular, we expect that the coming to full operations of our Eni Slurry Technology plant in the Sannazzaro refinery aimed at the full conversion of the barrel will improve the competitiveness of our refining system; and (iv) improvement in refinery flexibility which is intended to increase the slate of processed crudes in order to capture any cost advantages in the marketplace.

In Marketing activities, where we expect continuing competitive pressure due to weak demand and large product availability, we are planning for achieving a gradual improvement in results of operations mainly by focusing on margin preservation. We will try to do this by means of effective marketing initiatives to retain customers, product and service innovation and a continuing focus on the quality of service and attractive promotional campaigns, the strength of the Eni brand targeting to complete the rebranding of the network, the automation of petrol stations and the expansion of non-oil activities. Management plans to improve the efficiency of the retail network by closing low-throughput outlets and other rationalizations. Retail operations abroad will be developed selectively and we are planning to divest from marginal areas.

With respect to short-term targets, management expects refining throughputs on Eni s account to decline slightly compared to 2013. This projection assumes the full operation of the new conversion, EST-based unit at the Sannazzaro plant which effects will be more than offset by continuing capacity reduction. Also retail sales of refined products in Italy and the Rest of Europe are expected to decline slightly compared with 2013 due to an anticipated contraction in demand in Italy and network restructuring in European markets.

Based on the planned industrial actions, management expects the Refining & Marketing business to break even by the plan period, assuming the same depressed trading environment as in 2013.

Chemicals

Eni s chemical operations are exposed to volatile costs of oil-based feedstock and the cyclicality of demand due to the commoditized nature of Eni s product portfolio and underlying weaknesses in the industry. Our commodity chemical businesses have been unprofitable in recent years and we do not expect any improvement in their profitability outlook for the foreseeable future due to structural cost disadvantages with respect to Asian and Middle East players as well as a weak macroeconomic outlook which will hamper a sustainable recovery in demand and ongoing trends in crude oil prices. Against this backdrop management intends to seek to recover profitability at its Chemical segment by progressively reducing the exposure to loss-making commodity chemicals. This will be achieved by cutting production capacity by 5% in the plan period which will add to the 25% cut achieved in 2013 due to the shut down of a plant in Sardinia in order to convert it into a facility for the production of chemicals based on green feedstock, as well as the restructuring of the Venice facility. Our return to profitability will be underpinned by a progressive growth in the production of chemicals based on green technologies and in niche productions such as elastomers where we have the competitive advantage granted by proprietary technologies. This will be also driven by the start-up in the plan period of certain projects to jointly product and market elastomers with Asian partners in Malaysia and South Korea. Management plans to continue efficiency actions, cost savings and rationalization initiatives at loss-making plants.

Management expects to achieve the break-even in the chemical business by end of the plan period assuming the trading environment to be as unfavorable as in 2013.

Engineering & Construction

The Engineering & Construction segment faced sharply lower profitability in 2013 compared to 2012 due to a slowdown in business activities and large losses which were recorded at certain contract works due to a worsening trading environment and customer relationship and management issues. The sharp contraction in profitability negatively impacted the share performance of our listed subsidiary Saipem. The business underwent profound operational and organizational changes, a more selective commercial strategy was adopted and a new management team was put in place.

Over the four year plan we confirm the segment s target of consolidating its global competitive position in the Offshore and Onshore businesses and its role as high-quality niche player in the deepwater drilling business. Saipem will leverage on the enhancement of the EPC(I)-oriented business model, its world-class technology, engineering and delivering skills, its strong local presence and established relationships with other major oil companies and national oil companies to regain profitability. In this light, Saipem aims to strengthen its construction ability particularly in large, highly-complex projects, in harsh environments, keeping a selective commercial approach. However, we believe that 2014 will be a transitional year with a recovery in profitability, the degree of which relies upon effective execution of operational and commercial activities at low-margin contracts still present in the current portfolio, in addition to the speed at which bids underway will be awarded.

Capital expenditure plans

Over the next four years, the Company plans to invest euro 54 billion in its businesses to support continued organic growth; approximately 83%, 3%, 4%, 4% and 5% of planned capital expenditures is expected to be directed to the Exploration & Production, Gas & Power, Refining & Marketing, the Chemical and the Engineering & Construction segments, respectively. The planned amounts of expenditures also include capital allocation to joint venture projects and associates.

We plan to allocate the largest portion of resources amounting to some euro 38 billion to continuing development activities in our Exploration & Production segment to fuel production growth. Project start-ups and plateau enhancement at existing fields will be geographically diversified and executed mainly in Nigeria, Angola, Indonesia, Congo, Norway, Kazakhstan and Venezuela and the start of development activities in Mozambique which will target production growth beyond the plan period.

Exploration projects will be allocated approximately euro 5.6 billion, intended to pursue finding projects in well-established basins and in high potential frontier areas.

In the Gas & Power business the main investment projects will target the South Stream project, certain green projects and improvement of combined-cycle power plants flexibility.

In the Refining & Marketing segment we plan to make selective capital expenditures mainly targeted to refinery upgrade of conversion capacity and flexibility as well as plant reliability and security. We plan to finalize the project to convert the Venice plant into a "bio-refinery" to produce bio-fuels. Other capital projects will be directed to network upgrading and the completion of the rebranding of service stations to the "Eni" logo.

In the Chemical business we plan to selectively expand capacity in the best-positioned lines of business (namely elastomers), while targeting plant efficiency, reliability and energy savings in other areas, including the restructuring and upgrading of the loss-making sites. We plan to finalize the project to convert the Porto Torres plant into a bio-chemical complex and to develop strategic initiatives in the field of elastomers in emerging markets.

Following the completion of assets expansion program (fleet and yards) which has been carried out in the last years, 2014-2017 Saipem Investment Plan envisages a slowdown. Excluding the new construction yard in Brazil to be completed in 2014, capital expenditures will be mainly related to fleet maintenance/substitutions, major upgrades on offshore fleet (including investments to cope with HSE high standards), equipment for the execution of awarded/expected projects ("project specific") and investments in strategic areas ("local content").

Eni s capital expenditure program is expected to be lower than the previous industrial plan, down by approximately 5%. This will be driven by postponing certain development phases at our long-plateau projects in the Exploration & Production segment.

In the year 2014, management expects a capital budget in line with 2013 (euro 12.8 billion in capital expenditure and euro 0.32 billion in financial investments in 2013).Management expects to pursue strict capital discipline when assessing individual capital projects.

Management is assuming the oil price to decline from an expectation of 104 $/BBL in 2014 down to 90 $/BBL in 2017; longer-term management is assuming an oil price of 90 $/BBL that is adjusted to take account of expected inflation from 2018 onwards. The internal rate of return of each project is compared to the relevant hurdle rate, differentiated by business segment and country of operation. These hurdle rates are calculated taking into account: (i) the weighted average cost of capital to the Group. In 2013, management assessed that the cost of capital to the Group marginally decreased from the previous year mainly reflecting a reduction in the premium for the sovereign risk incorporated into the yields on Italian ten-year bonds. The other financial parameters used for assessing the cost of capital: market risk premium, cost of borrowings to Eni determined by expected trends in borrowing spreads and management s estimates about the composition of the Company s financial debt and ratio of net borrowings to equity, were down fractionally or unchanged from the previous reporting period; (ii) an appreciation of the country risk which factors in the perceived level of risk associated with each country of operations in terms of current trends and conditions in the macroeconomic, business, regulatory and socio political framework, as well as the consensus outlook; and (iii) a premium for the business risk.

Liquidity and leverage

In the foreseeable future, management is focused on preserving a solid balance sheet and strengthening the Company s financial structure, seeking to maintain its key ratio of net borrowings to equity leverage within the range of 0.1-0.3. At the end of 2013, leverage stood at 0.25 substantially unchanged from the previous reporting period. Management believes that this target range in leverage is consistent with the Company s business profile, which features greater exposure to the Exploration & Production segment than in previous years reflecting the divestment of Italian gas transport activities which occurred at the end of 2012. See "Item 4 Business developments".

For planning purposes, management projected the Company s expected cash flows assuming a declining scenario of Brent prices down from 104 $/BBL in 2014 to 90 $/BBL in 2017 to assess the financial compatibility of its capital expenditure programs and dividend policy with internal targets of ratio of total equity to net borrowings. Under those pricing assumptions, in 2014 the ratio of net borrowings to total equity is projected to be substantially in line with the level achieved at the end of 2013 leveraging on cash flows from operations and portfolio management.

Going forward, management expects that the projected future cash flows from operations will provide enough resources to fund capital expenditures plans, to pay a regular dividend the amount of which will be set in accordance to our progressive dividend policy and to maintain leverage within the above mentioned range. We expect that our cash flow from operations will grow at a healthy rate along the plan period. This will be driven by increased cash generation in our Exploration & Production segment which will be underpinned by profitable production growth, cost control and capital discipline, as well as the restructuring of our Gas & Power, Refining & Marketing and Chemical businesses which will turn cash positive in the plan period due to contract renegotiations, expansion in profitable market segments and reduced exposure to the commodity risk. Furthermore, management expects to deliver approximately euro 9 billion of additional cash flows from asset disposals, of which euro 2.2 billion have been already cashed-in following the closing of the disposal of our interest in Artic Russia early in January 2014. In March 2014, we also divested a 7% stake in Galp for a cash consideration of euro 0.7 billion. Our cash flow projections are based on our declining Brent scenario down progressively from 104 $/BBL in 2014 to 90 $/BBL in 2017. We note that the Brent price in the period January 1 to March 31, 2014 was 108 $/BBL on average. We estimated that our cash flow from operations may improve by approximately euro 0.1 billion for each dollar increase in Brent prices on a yearly basis. Finally, consistent with our target range of leverage, we may consider boosting cash returns to shareholders via our flexible, multi-year buyback program, whereby we plan to repurchase up to 10% of outstanding Eni s shares, with a spending ceiling which will comply with the authorization of the Shareholders Meeting up to a maximum of euro 6,000 million.

For planning purposes, management assumed an average exchange rate of 1.30 U.S. dollars per euro in the 2014-2017 period. Given the sensitivity of Eni s results of operations to movements in the euro versus the U.S. dollar exchange rate, trends in the currency market represent a factor of risk and uncertainty. See "Item 3 Risk factors".

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Dividend policy

Management plans to pay a dividend of euro 1.10 per share for fiscal year 2013 subject to approval from the General Shareholders Meeting scheduled for May 8, 2014. Of this, euro 0.55 per share was paid in September 2013 as an interim dividend with the balance of euro 0.55 per share expected to be paid in late May 2014. The dividend for fiscal year 2013 represented an increase of 2% compared to the 2012 dividend.

The Company dividend policy contemplates growing dividends at a rate which is expected to be determined year to year taking into account Eni s underlying earnings and cash flow growth as well as capital expenditure requirements and the targeted financial structure. Management will also evaluate the achievement of the targeted production levels in the Exploration & Production segment, the status of renegotiations at gas long-term supply contracts in the Gas & Power segment and the delivery on efficiency gains in the other businesses. This dividend policy is based on management s planning assumptions of a declining Brent scenario down from 104 $/BBL in 2014 to 90 $/BBL in 2017. Considering all these variables, management expects to propose to Shareholders approval a dividend of euro 1.12 per share for fiscal year 2014, an increase of approximately 1.8% from 2013.

In future years, management expects to continue paying interim dividends for each fiscal year, with the balance for the full-year dividend paid in the following year.

Management is also planning to continue repurchasing the Eni shares, which has been authorized by the Shareholders Meeting for a total amount of euro 6 billion. Share repurchases have commenced since the beginning of 2014; see Item 16E. In the future, share repurchases will be executed at management s sole discretion and when a number of conditions are met. These include, but are not limited to, current trends in the trading environment, a level of leverage which management assesses to be appropriate in light of market conditions and well within our target range limit of 0.3, and full funding of capital expenditure requirements and dividends throughout the plan period.

The expectations described above are subject to risks, uncertainties and assumptions associated with the oil and gas industry, and economic, monetary and political developments in Italy and globally that are difficult to predict. There are a number of factors that could cause actual results and developments to differ materially, including, but not limited to, political instability in Libya and other countries, crude oil and natural gas prices; demand for oil and gas in Italy and other markets; developments in electricity generation; price fluctuations; drilling and production results; refining margins and marketing margins; currency exchange rates; general economic conditions; political and economic policies and climates in countries and regions where Eni operates; regulatory developments; the risk of doing business in developing countries; governmental approvals; global political events and actions, including war, terrorism and sanctions; project delays; material differences from reserves estimates; inability to find and develop reserves; technological development; technical difficulties; market competition; the actions of field partners, including the inability of joint venture partners to fund their share of operating or developments activities; industrial actions by workers; environmental risks, including adverse weather and natural disasters; and other changes to business conditions. Please refer to "Item 3 Risk factors".

Off-balance sheet arrangements

Eni has entered into certain off-balance sheet arrangements, including guarantees, commitments and risks, as described in "Item 18 note 35 Guarantees, commitments and risks of the Notes to the Consolidated Financial Statements". Eni s principal contractual obligations, including commitments under take-or-pay or ship-or-pay contracts in the gas business, are described under "Contractual Obligations" below. See the Glossary for a definition of take-or-pay or ship-or-pay clauses.

Off-balance sheet arrangements comprise those arrangements that may potentially impact Eni s liquidity, capital resources and results of operations, even though such arrangements are not recorded as liabilities under generally accepted accounting principles. Although off-balance sheet arrangements serve a variety of Eni s business purposes, Eni is not dependent on these arrangements to maintain its liquidity and capital resources; nor is management aware of any circumstances that are reasonably likely to cause the off-balance sheet arrangements to have a material adverse effect on the Company s financial condition, results of operations, liquidity or capital resources.

Eni has provided various forms of guarantees on behalf of unconsolidated subsidiaries and affiliated companies, mainly relating to guarantees for loans, lines of credit and performance under contracts. In addition, Eni has provided guarantees on the behalf of consolidated companies, primarily relating to performance under contracts. These arrangements are described in "Item 18 note 35 Guarantees, commitments and risks of the Notes to the Consolidated Financial Statements".

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Contractual obligations

Amounts in the table refer to expected payments, undiscounted, by period under existing contractual obligations commitments.

	Maturity year						
	Total	**2014**	**2015**	**2016**	**2017**	**2018**	**2019 and thereafter**
				(euro million)			
Total debt	**26,589**	**5,285**	**3,943**	**3,212**	**2,942**	**1,392**	**9,815**
Long-term finance debt	22,758	1,737	3,700	3,211	2,937	1,392	9,781
Short-term finance debt	2,553	2,553					
Fair value of derivative instruments	1,278	995	243	1	5		34
Interest on finance debt	**4,859**	**818**	**710**	**650**	**557**	**429**	**1,695**
Guarantees to banks	**172**	**172**					
Non-cancelable operating lease obligations (1)	**2,267**	**706**	**423**	**335**	**263**	**191**	**349**
Decommissioning liabilities (2)	**14,342**	**214**	**162**	**206**	**304**	**331**	**13,125**
Environmental liabilities (3)	**1,716**	**279**	**329**	**246**	**126**	**114**	**622**
Purchase obligations (4)	**241,166**	**21,202**	**20,203**	**17,843**	**16,335**	**15,404**	**150,179**
Natural gas to be purchased in connection with take-or-pay contracts (5)	226,535	18,228	18,724	16,427	14,967	14,277	143,912
Natural gas to be transported in connection with ship-or-pay contracts (5)	10,560	1,801	1,218	1,168	1,130	894	4,349
Other take-or-pay and ship-or-pay obligations	1,066	130	125	118	109	104	480
Other purchase obligations (6)	3,005	1,043	136	130	129	129	1,438
Other obligations (7)	**138**	**3**	**3**	**3**	**3**	**3**	**123**
of which:							
- Memorandum of intent relating to Val d Agri	*138*	*3*	*3*	*3*	*3*	*3*	*123*
	291,249	**28,679**	**25,773**	**22,495**	**20,530**	**17,864**	**175,908**

(1) Operating leases primarily regarded assets for drilling activities, time charter and long-term rentals of vessels, lands, service stations and office buildings. Such leases did not include renewal options. There are no significant restrictions provided by these operating leases which limit the ability of the Company to pay dividend, use assets or to take on new borrowings.
(2) Represents the estimated future costs for the decommissioning of oil and natural gas production facilities at the end of the producing lives of fields, well-plugging, abandonment and site restoration.
(3) Environmental liabilities do not include the environmental charge amounting to euro 1,109 million for the proposal to the Ministry of the Environment to enter into a global transaction related to nine sites of national interest because the dates of payment cannot be reasonably estimated.
(4) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms.
(5) Such arrangements include non-cancelable, long-term contractual obligations to secure access to supply and transport of natural gas, which include take-or-pay clauses whereby the Company obligations consist of collecting minimum quantities of product or service or paying the corresponding cash amount that entitles the Company to collect the product in future years. Future obligations in connection with these contracts were calculated by applying the forecasted prices of energy or services included in the four-year business plan approved by the Company s Board of Directors and on the basis of the long-term market scenarios used by Eni for planning purposes to minimum take and minimum ship quantities. See Item 4 Gas & Power Supply of natural gas and Item 3 Risk factors Risks in the Company Gas & Power business for a discussion of nature and importance of Eni s take-or-pay contracts and the related risks from the evolving regulatory environment that could negatively impact Eni s results.
(6) Mainly refers to arrangements to purchase capacity entitlements at certain re-gasification facilities in the United States of euro 1,911 million.
(7) In addition to these amounts, Eni has certain obligations that are not contractually fixed as to timing and amount, including contributions to defined benefit pension plans (see "Item 18 note 23 Trade and other payables of the Notes to the Consolidated Financial Statements").

The table below summarizes Eni s capital expenditure commitments for property, plant and equipment as of December 31, 2013. Capital expenditures are considered to be committed when the project has received the appropriate level of internal management approval. Such costs are included in the amounts shown.

	Total	2014	2015	2016	2017	2018 and thereafter
			(euro million)			
Committed on major projects	36,784	5,697	5,246	4,908	3,224	17,709
Other committed projects	17,892	7,555	4,902	2,865	1,705	865
	54,676	**13,252**	**10,148**	**7,773**	**4,929**	**18,574**

Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the Group may not be available, or the Group is unable to sell its assets on the market place as to be unable to meet short-term finance requirements and to settle obligations.

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Such a situation would negatively impact Group results as it would result in the Company incurring higher borrowing expenses to meet its obligations or under the worst of conditions the inability of the Company to continue as a going concern. At present, the Group believes it has access to sufficient funding and has also both committed and uncommitted borrowing facilities to meet currently foreseeable borrowing requirements. The Group has also established a cash reserve which consists of cash on hand and very liquid securities the amount of which according to management plans can alternatively be used to absorb temporary swings in cash flows from operations, to provide financial flexibility to pursue the Group development programs or ensure the funding of the Group contractual obligations with respect to the repayment of financing debt at maturity over a 24-month horizon. For a description of how the Company manages the liquidity risk see "Item 18 note 35 of the Notes to the Consolidated Financial Statements".

At December 31, 2013, Eni maintained short-term committed and uncommitted unused borrowing facilities of euro 14,328 million, of which euro 2,141 million were committed, and long-term committed unused borrowing facilities of euro 4,719 million. These facilities bore interest rates that reflected prevailing market conditions. Fees charged for unused facilities were immaterial. Eni has in place a program for the issuance of Euro Medium Term Notes up to euro 15 billion, of which about euro 13.7 billion were drawn as of December 31, 2013.

Working capital

Management believes that, taking into account unutilized credit facilities, Eni s credit rating and access to capital markets, Eni has sufficient working capital for its foreseeable requirements.

Credit risk

Credit risk is the potential exposure of the Group to losses in case counterparties fail to perform or pay amounts due.

For a description of how the Company manages the credit risk see "Item 18 note 35 of the Notes to the Consolidated Financial Statements".

For information about credit losses in 2013 and the allowance for doubtful accounts see "Item 18 note 10 of the Notes to the Consolidated Financial Statements".

Market risk

In the normal course of its operations, Eni is exposed to market risks deriving from fluctuations in commodity prices and changes in the euro versus other currencies exchange rates, particularly the U.S. dollar, and in interest rates. For a description of how the Company manages the Market risk see "Item 18 note 35 of the Notes to the Consolidated Financial Statements".

Research and development

For a description of Eni s research and development operations in 2013, see "Item 4 Research and development".

Item 6. DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

Directors and Senior Management

The following table lists the Company s Board of Directors as at April 2014:

Name	Position	Year elected or appointed	Age
Giuseppe Recchi	Chairman	2011	50
Paolo Scaroni	CEO	2005	67
Mario Resca	Director	2002	68
Paolo Marchioni	Director	2008	44
Francesco Taranto	Director	2008	73
Carlo Cesare Gatto	Director	2011	72
Alessandro Lorenzi	Director	2011	65
Roberto Petri	Director	2011	64
Alessandro Profumo	Director	2011	57

In accordance with Article 17.1 of Eni s By-laws, the Board of Directors is made up of 3 to 9 members.

The current Board of Directors was elected by the ordinary Shareholders Meeting held on May 5, 2011, which also established the number of Directors at nine for a term of three financial years. The Board s term will therefore expire with the Shareholders Meeting called to approve the financial statements for the year ending December 31, 2013, expected for May 8, 2014.

The Board of Directors is appointed by means of a slate voting system: slates may be presented by the shareholders representing at least 0.5% of share capital. According to Eni By-laws, three out of nine Directors are appointed from among the candidates of the non-controlling shareholders.

Giuseppe Recchi, Paolo Scaroni, Carlo Cesare Gatto, Paolo Marchioni, Roberto Petri and Mario Resca were candidates of the Ministry of the Economy and Finance. Alessandro Lorenzi, Alessandro Profumo and Francesco Taranto were candidates of institutional investors (non-controlling shareholders).

The Shareholders Meeting appointed Giuseppe Recchi as the Chairman of the Board of Directors and, on May 6, 2011, the Board appointed Paolo Scaroni as the Chief Executive Officer of the Company.

On the basis of Italian laws regulating the special powers of the State (see "Item 10 Stock ownership limitation and voting rights restrictions"), the Minister of the Economy and Finance, in agreement with the Minister of Economic Development, may appoint another member of the Board of Directors, without voting rights, in addition to those appointed by the Shareholders Meeting. On the occasion of the last Board appointment, the Minister of the Economy and Finance opted not to exercise that power. Law Decree No. 21 of March 15, 2012, ratified with amendments by Law No. 56 of May 11, 2012, modified Italian legislation governing the special powers of the State to comply with European rules. The previous provisions (Article 2 of Law Decree No. 332/1994 ratified by Law No. 474/1994 and its implementing decrees), as well as the provisions of the By-laws which are inconsistent with the new rules, will be repealed by the last of the implementing ministerial regulations in the areas of energy, transport and communications. If the afore mentioned implementing decrees, approved on March 14, 2014 by the Italian Council of Ministers, came into force at the date of the approval of the present Form, the provisions set forth in Article 2 of the Law Decree

No. 332/1994 would be repealed. The provisions regarding the stock ownership limitations and voting rights restrictions pursuant to Article 3 of Law No. 474/1994 remain in force.

The following provides details on the personal and professional profiles of the Directors.

Giuseppe Recchi was born in 1964 and has been Chairman of the Board of Eni since May 2011. He is also member of the Board of Directors and the Internal Control and Risk Committee of Exor SpA; Director of GE Capital Interbanca SpA and member of the Massachusetts Institute of Technology E.I. External Advisory Board. He is also member of the Italian Corporate Governance Committee, the Executive Committees of Confindustria (where he chairs the Foreign Investment Committee), Assonime (Association of Italian Joint Stock Companies), Aspen Institute Italia; member of the Board of Directors of FEEM-Eni Enrico Mattei Foundation, of the Italian Institute of Technology and of the LUISS Business School Advisory Board. He is Co-Chair of the Italy-China Foundation, Co-Chair of the B20 Task Force on Improving Transparency and Anti-Corruption and Director of the World Economic Forum Partnering Against Corruption Initiative. He graduated in Engineering at the Polytechnic of Turin. In 1989, he started his career as entrepreneur at Recchi SpA, a general contractor active in 25 countries in the construction of high tech public

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infrastructure. Since 1994 he has served as Executive Chairman of Recchi America Inc, the U.S. branch of the Group. In 1999, he joined General Electric, where he held several managerial positions in Europe and in the United States. He served as Director of GE Capital Structure Finance Group; Managing Director for Industrial M&A and Business Development of GE EMEA; President & CEO of GE Italy. Until May 2011, he was President & CEO of GE South Europe. Until March 2014, he was member of the European Advisory Board of Blackstone. Mr. Recchi has been member of the Honorary Committee for the Rome Candidacy to the 2020 Olympic Games, member of the Board of Permasteelisa SpA Advisory Board member of Invest Industrial (private equity) and visiting Professor in Structured Finance at Turin University.

Paolo Scaroni has been Chief Executive Officer of Eni since June 2005. He is currently a Non-Executive Director of Assicurazioni Generali, Non-Executive Deputy Chairman of London Stock Exchange Group, Non-Executive Director of Veolia Environnement. Besides is in the Board of Overseers of Columbia Business School and Fondazione Teatro alla Scala. After graduating in economics at the Università Luigi Bocconi in Milan in 1969, he worked for three years at Chevron, before obtaining an MBA from Columbia University, New York, and continuing his career at McKinsey. In 1973, he joined Saint Gobain, where he held a series of management positions in Italy and abroad, until his appointment as head of the Glass Division in Paris. From 1985 to 1996, he was Deputy Chairman and Chief Executive Officer of Techint. In 1996, he moved to the United Kingdom and was Chief Executive Officer of Pilkington until May 2002. From May 2002 to May 2005, he was Chief Executive Officer and Chief Operating Officer of Enel. In 2005 and in 2006, he was Chairman of Alliance Unichem. In May 2004, he was appointed Cavaliere del Lavoro of the Italian Republic. In June 2013, he was made a Commandeur da la Légion d Honneur.

Mario Resca was born in Ferrara in 1945 and has been a Director of Eni since May 2002. He graduated in Economics and Business at the Università Luigi Bocconi of Milan. He is Chairman of Confimprese, Chairman of Bioenergy C.G. and Director of Mondadori SpA. After graduating he joined Chase Manhattan Bank. In 1974, he was appointed manager of Saifi Finanziaria (Fiat Group) and from 1976 to 1991 he was a partner and Country Mgr of Egon Zehnder. In this period he was appointed Director of Lancôme Italia and of companies belonging to the RCS Corriere della Sera Group and the Versace Group. From 1995 to 2007, he was Chairman and Chief Executive Officer of McDonald s Italia. He was also Chairman of Sambonet SpA and Kenwood Italia SpA, a founding partner of Eric Salmon & Partners, Chairman of the American Chamber of Commerce, General Director of Italian Heritage and Antiquities in the Ministry of Cultural Heritage and Activities and Chairman of Convention Bureau Italia SpA. He was also Extraordinary Commissioner of Cirio Del Monte. He was decorated as a Cavaliere del Lavoro in June 2002.

Paolo Marchioni was born in Verbania in 1969 and has been a Director of Eni since June 2008. He is a qualified lawyer specializing in penal and administrative law, counselor in the Supreme Court and superior jurisdictions. He has been Chairman of the Board of Directors of Finpiemonte Partecipazioni SpA since August 2010. He acts as a consultant to government agencies and business organizations on business, corporate, administrative and local government law. He was Mayor of Baveno (Verbania) from April 1995 to June 2004 and Chairman of the Assembly of Mayors of Con.Ser.Vco from September 1995 to June 1999. Until June 2004, he was a member of the Assembly of Mayors of the Asl 14 health authority, the steering committee of the Verbania health district, the Assembly of Mayors of the Valle Ossola waste water consortium, the Assembly of Mayors of the Verbania social services consortium. From April 2005 to January 2008, he was a member of the Stresa city council. From October 2001 to April 2004, he was a Director of CIM SpA of Novara (merchandise interport center) and from December 2002 to December 2005, Director and executive committee member of Finpiemonte SpA. From June 2005 to June 2008 he was a Director of Consip SpA. He was Provincial Councillor in charge of balance, property, legal affairs and production activities and Vice-President of the Province of Verbano-Cusio-Ossola from June 2009 to October 2011. He was Director of the Provincial Board of the Province of Verbano-Cusio-Ossola from October 2011 to November 2012.

Francesco Taranto was born in Genoa in 1940 and has been a Director of Eni since June 2008. He is currently Vice Chairman of Banca CR Firenze SpA (Cassa di Risparmio di Firenze SpA). He is also a Director and member of the

Executive Committee of Rimorchiatori Riuniti SpA. He started working in 1959 in a stock brokerage in Milan; from 1965 to 1982, he worked at Banco di Napoli as deputy manager of the stock market and securities department. He held a series of managerial positions in the asset management field, notably as manager of securities funds at Eurogest from 1982 to 1984, and General Manager of Interbancaria Gestioni from 1984 to 1987. After moving to the Prime group (1987 to 2000), he was Chief Executive Officer of the parent company for a long period. He was Director of ERSEL S.I.M., member of the steering council of Assogestioni and of the Corporate Governance Committee for listed companies formed by Borsa Italiana. He was a Director of Enel from October 2000 to June 2008.

Carlo Cesare Gatto was born in Murazzano (Cuneo) in 1941 and has been a Director of Eni since May 2011. He graduated in Economics and Business at the Università degli Studi of Turin. He is a registered public auditor. He is currently Chairman of the Board of Statutory Auditors of Rai SpA, Natuzzi SpA, Difesa Servizi SpA, Rainet SpA; effective Statutory Auditor of Rai Pubblicità SpA and Director of Arcese Trasporti SpA. He was teacher of Finance, Administration and Control at the Isvor Fiat SpA training institute. In 1968, he was hired by Impresit as Chief Accountant, where he managed, in Jordan, the finance department of the local branch. He joined the Fiat Group in 1969 where over the years he held a series of increasing responsibility positions in the area of finance, administration and control. From 1979 to 1990, he was Head of Financial Reporting at the Fiat Group and also had responsibility for the control of the transport companies (Sapav, Sadem, Sita) run under concession by the Fiat Group and for which he subsequently oversaw the sale. In 1990, he was appointed Joint Manager of Finance and Control of the Fiat Group, before becoming, in 1998, Chief Administration Officer (CAO) of the Fiat Group. From 2000 to 2004, he was Chief Executive Officer and Deputy Chairman of Business Solution, a new sector created by Fiat for the supply of business services. In 1993, he was the Italian Representative at the European Commission for the fiscal harmonization of member States. In 1992, he was decorated as Cavaliere dell Ordine al Merito della Repubblica Italiana and, in 1995, as Ufficiale dell Ordine al Merito della Repubblica Italiana.

Alessandro Lorenzi was born in Turin in 1948 and has been a Director of Eni since May 2011. He is currently a founding partner of Tokos Srl, consulting firm for securities investment, Chairman of Società Metropolitana Acque Torino SpA, Director of Ersel SIM SpA, Millbo SpA and Sicme Motori Srl. He began his career at SAIAG SpA, in the Administration and Control area. In 1975, he joined Fiat Iveco SpA where he held a series of positions: Controller of Fiat V.I. SpA, Head of Administration, Finance and Control, Head of Personnel of Orlandi SpA in Modena (1977-1980) and Project Manager (1981-1982). In 1983, he joined the GFT Group, where he was Head of Administration, Finance and Control of Cidat SpA, a GFT SpA subsidiary (1983-1984), Central Controller of the GFT Group (1984-1988), Head of Finance and Control of the GFT Group (1989-1994) and Managing Director of GFT SpA, with ordinary and extraordinary powers over all operating activities (1994-1995). In 1995, he was appointed Chief Executive Officer of SCI SpA, where he oversaw the restructuring process. In 1998, he was appointed Central Manager and, subsequently, Director of Ersel SIM SpA, until June 2000. In 2000, he became Central Manager of Planning and Control at the Ferrero Group and General Manager of Soremartec, the technical research and marketing company of the Ferrero Group. In May 2003, he was appointed CFO of the Coin Group. In 2006 he became Central Corporate Manager at Lavazza SpA, becoming member of the Board of Directors from 2008 to June 2011.

Roberto Petri was born in Pescara in 1949 and has been a Director of Eni since May 2011. He graduated in law at the Università degli Studi "Gabriele D Annunzio" of Chieti and Pescara. He has been Chairman of Italimmobili Srl since 2011. In 1976, he was hired by Banca Nazionale del Lavoro (BNL) where he held a series of positions: Head of the "Overdrafts Advisory" of BNL in Busto Arsizio (1982), Deputy Manager for the industrial division at the BNL branch in Ravenna (1983-1987), Area Chief of BNL in Venice (1987-1989) and Joint Manager of the central office of BNL in Rome (1989-1990). In 1990, he was appointed commercial manager at Banca Popolare and in 1994 he moved, with the same position, to Cassa di Risparmio di Ravenna Group (Carisp Ravenna and Banca di Imola). From 2001 to 2006, he was Chief Secretary to the Under-Secretary of Defense, where he was mainly involved in the Department s contacts with industry and international relations. From 2008 to 2011, he was Chief Secretary at the Minister of Defense. From 2003 to 2006, he was a Director of Fintecna SpA and from 2005 to 2008 a Director of Finmeccanica SpA.

Alessandro Profumo was born in Genoa in 1957 and has been Director of Eni since May 2011. He graduated in Business Administration at the Università Luigi Bocconi of Milan. He is currently Chairman of Banca Monte dei Paschi di Siena, of Appeal Strategy & Finance Srl and member of the Supervisory Board of Sberbank. He is also member of the Board of Directors of the Bocconi University in Milan. He began his career in 1977 at the Banco Lariano, becoming Branch Manager in Milan. In 1987, he joined McKinsey where he was Project Manager in the strategy area for the finance sector. In 1989, he was appointed Head of relations with financial institutions and integrated development projects at Bain, Cuneo e Associati firm (now Bain & Company). In 1991, he left the field of company consultancy to join RAS, Riunione Adriatica di Sicurtà, where he was given responsibility, as General Manager, for the banking and parabanking sectors. He was also in charge of the yield increase of that company s bank and of the other group companies operating in the field of asset management. In 1994, he joined Credito Italiano as Joint Central Manager, with responsibility for Programming and Control, becoming General Manager in 1995. In 1997, he was appointed Chief Executive Officer of Credito Italiano and subsequently of Unicredit, a position he held until September 2010. On an international level he was Chairman of the European Banking Federation and Chairman of the IMC Washington. In May 2004, he was decorated as Cavaliere del Lavoro.

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Senior Management

The table below sets forth the composition of Eni s Senior Management as at December 31, 2013. It includes the CEO, as General Manager of Eni SpA, the Chief Operating Officers, the Chief Financial Officer, the Chief Corporate Operations Officer and the Executives who report directly to the CEO (*).

Name	Management position	Year first appointed to current position	Total number of years of service at Eni	Age
Paolo Scaroni	General Manager of Eni	2005	9	67
Claudio Descalzi	Exploration & Production Chief Operating Officer	2008	33	58
Angelo Fanelli	Refining & Marketing Chief Operating Officer	2010	33	61
Massimo Mondazzi	Chief Financial Officer	2012	22	50
Salvatore Sardo	Chief Corporate Operations Officer	2008	9	61
Stefano Lucchini	International Relations and Communication Senior Executive Vice President	2005	9	51
Massimo Mantovani	General Counsel Legal Affairs Senior Executive Vice President	2006	21	50
Roberto Ulissi	Company Secretary Corporate Affairs and Governance Senior Executive Vice President	2006	8	51
Marco Petracchini	Internal Audit Senior Executive Vice President	2011	15	49
Marco Alverà	Midstream Senior Executive Vice President	2012	9	38
Salvatore Meli	Research and Technological Innovation Executive Vice President	2011	32	60
Leonardo Bellodi	Government Affairs Executive Vice President	2012	8	48
Stefano Leofreddi	Integrated Risk Management Senior Vice President	2012	28	53
Raffaella Leone	Executive Assistant to the CEO	2005	9	51

(*)

As of July 2013, the activities of the Gas & Power Division, due to the reorganization of the business, have been reassigned to the Midstream and to the Downstream Gas & Power Departments.

The Chief Operating Officers, the Chief Financial Officer, the Chief Corporate Operations Officer and the Executive Assistant to the CEO, the Senior Executive Vice Presidents and the Government Affairs Executive Vice President and the Chief Executive Officer of Versalis SpA are permanent members of the Management Committee[6], which advises and supports the CEO.

The Chief Operating Officers, the Chief Financial Officer and the Senior Executive Vice President of the Internal Audit Department are appointed by the Board of Directors, acting upon a proposal of the CEO in agreement with the Chairman. Other members of Eni s senior management are appointed by Eni s CEO and may be removed without cause, except for the Senior Executive Vice President of the Internal Audit Department and the Company Secretary, who are appointed by the Board of Directors, the latter upon a proposal of the Chairman.

Senior Managers

Claudio Descalzi was born in Milan in 1955. He graduated in Physics in 1979 at the Politecnico di Milano. He joined Eni in 1981 as an Oil-Gas field petroleum engineering and project manager, for the development of the North Sea, Libya, Nigeria, and Congo. In 1990, he was appointed Head of reservoir and operating activities for Italy. In 1994, he was named Managing Director of the Eni subsidiary in Congo and in 1998 Vice Chairman and Managing Director of Eni s subsidiary in Nigeria. From 2000 to 2001, he held the position of Executive Vice President for Africa, Middle

(6) The Internal Audit Senior Executive Vice President attends the meeting of the Management Committee only for matters that lie within his competence.

East and China. From 2002 to 2005, he was Executive Vice President for Italy, Africa, Middle East covering also the role of Chairman of the Board of several Eni subsidiaries in the area. In 2005, he was appointed Deputy Chief Operating Officer of Eni Exploration & Production Division. In 2012, he was the first European to receive the prestigious "Charles F. Rand Memorial Gold Medal 2012" award by the Society of Petroleum Engineers and the American Institute of Mining Engineers. He is currently President of Assomineraria and Vice President of Confindustria Energia. Since July 2008, he has been Chief Operating Officer of Eni Exploration & Production Division.

Angelo Fanelli was born in Rome in 1952. He has a degree in mechanical engineering from the La Sapienza University in Rome. After gaining experience at other companies, he joined the Eni Group in 1981, and in the first seven years held "field" positions in the Extra-network and Network markets as Technical Assistant, Lubricants and Sales Promoter on the Motorway Network. From 1988 to 1993, he was Head of the Bologna and Florence sales areas. From 1994 to 2004, he held a number of positions in the Network sector. He was appointed Head of Road Network Management, Head of the Ordinary Network and subsequently Head of Business Network Italy and Head of the Agip Road Transport Division, before becoming Head of Retail Business at the Refining & Marketing Division. From 2003 to 2004, he was Chairman and Managing Director of AgipRete SpA. In 2004, he was appointed Commercial Director Italy, a job he held until 2005 when he took up the position of Head of Logistics at the Genoa headquarters. In 2006, he was appointed Commercial Director (Executive Vice President) of the Refining & Marketing. From 2008 to December 31, 2012, he was a member of the board of Europia in Brussels. On April 6, 2010, he was appointed Chief Operating Officer of Eni SpA - Refining & Marketing. Since April 2010, he has been Chairman of Eni Trading & Shipping SpA. Since 2010, he has been member of the Board of Eni Foundation. Since 2010, he has been Vice President of Unione Petrolifera. Since June 2012, he has been member of the steering council of AISCAT. Since 2012, he has been member of the Board of Unindustria Lazio. Since 2013, he has been member of the General Council of Confidustria Energia.

Massimo Mondazzi was born in Monza in 1963. He graduated from the University L. Bocconi in Milan in 1987 with a degree in Business Administration. Before joining Eni in 1992, his early career was spent gaining professional experience in industrial and consulting firms. He worked in the Administration and Control area of the Eni Exploration and Production Division until 2006, where he reached the level of Director. From 2006 to 2009, he was the Director of Planning and Control for the Eni Group, before returning to the Exploration & Production Division as the Executive Vice President for Central Asia, Far East and Pacific Region. During his tenure as Executive Vice President for Central Asia, Far East and Pacific Region, he has contributed to the consolidation of Eni s activities in the Exploration and Production Division, to the launch of new development projects and to Eni s entry into new countries. As of December 5, 2012, he is Chief Financial Officer of the Eni Group and Manager charged with preparing Company s financial reports pursuant to Article 154-*bis* of Italian Legislative Decree No. 58/1998.

Salvatore Sardo was born in Turin in 1952. He graduated in Economics from the University of Turin. He is also a Chartered Accountant and Auditor. He has been Chief Corporate Operations Officer of Eni SpA since November 2008, reporting to the Chief Executive Officer with responsibility for policies and control of procurement, the department of Human Resources and organization, the department of Information & Communication Technology, Health, Safety, Environment & Quality, Security, Compensation & Benefits and the subsidiary EniServizi. Since April 8, 2009, he has also been the Chairman of Eni Corporate University. From April 27, 2010 to October 15, 2012, he was also Chairman of Snam SpA[7]. In April 2013, he was appointed Chairman of Versalis and member of the Board of Directors of Eni Foundation. From 2005 at Eni SpA, he was appointed Senior Executive Vice President Human Resources and Business Services, reporting to the Chief Executive Officer, with responsibility for policies and control of the Information & Communication Technology department and the subsidiary EniServizi. From February 4, 2003, at Enel SpA, group head of Procurement, Services and Security, reporting to the Chief Executive, with a volume of procurement of over euro 3 billion. From October 1, 2001, head of the Real Estate and General Services operating unit of Telecom Italia, reporting to the Chief Executive. From November 2000, head of the Real Estate and Services business unit of Telecom Italia. From October 1999, operational head of the Real Estate Department of Telecom Italia. Chairman of EMSA, Chairman and Chief Executive of EMSA Servizi and Chairman and Chief Executive of IMMSI, a company listed on the Milan Stock Exchange, as well as operational Chairman of TELIMM, IMSER and Telemaco companies operating in the same sector. From 1998 to June 2001, Chairman of Seat Pagine Gialle SpA. From 1997, at Telecom Italia as deputy general manager of finance, administration and control. From 1981, at Stet as head of Control for manufacturing; in 1991, co-central director and from 1992 to 1996, central director of Planning and Control. From September 1976 to 1981, at Coopers & Lybrand as an auditor, rising to the position of supervisor. In July 2011, he was appointed Grande Ufficiale dell Ordine al Merito of Italian Republic. On June 2008 he was nominated Commendatore dell Ordine al Merito of Italian Republic. From April 2008 to April 2011, he was a member of the Board of Directors and the Remuneration Committee of Saipem SpA. He has also served as a standing statutory auditor of Italtel, Finsiel and Telecom Italia.

Stefano Lucchini was born in Rome in 1962. He is married with two children and has a degree in economics from the LUISS in Rome. His first job was in the research department at Montedison. After a period as assistant to the Chairman of the Energy and Commerce Committee of the U.S. Congress in Washington D.C., he was director of communications at Montedison USA in New York. Returning to Italy in 1993, he was responsible for financial communications and investor relations for the Montedison Group. He joined Enel in 1997 as Head of corporate

(7) Until January 1, 2012 the company name was Snam Rete Gas SpA.

communications, and investor relations (where he oversaw the company s IPO) and subsequently as the group s head of external relations. He has been the head of external relations for Confindustria, the Italian employers federation. In June 2002, he was appointed head of external relations for the Banca Intesa Group. In July 2005, he was appointed as Eni s Senior Executive Vice President of public affairs and corporate communication and, since July 2012, he has been Senior Executive Vice President of international relations and communication and chairman of Eni USA Inc. He teaches at the Advanced School of Journalism at Milan s Catholic University, for which he is also a member of the evaluation committee. Since 2007, he has been a member of the Supervisory Board of Confindustria and of the executive board of UPA. He is also a member of the boards of Censis, the Fondazione Eni Enrico Mattei (FEEM) and the Eni Foundation. Since 2005, he has been a member of the Board of Directors of AGI. He is a Grand Officer of Order of Merit of the Italian Republic and was awarded the Silver Cross Medal by the Italian Red Cross. He is a member of the Advisory Board for the LUISS MBA Program and member of the Board of Directors of both the American Chamber of Commerce in Italy and Unindustria and a director of the Energy Foundation. He is a visiting fellow at Oxford University.

Massimo Mantovani was born in Milan in 1963. He has a degree in Law from Università Statale di Milano (Italy) and a Master in Law (LLM) from the University of London (United Kingdom). He was admitted to practice law in Italy as avvocato and in England as solicitor. For around 5 years he worked for law firms in Milan and London. In 1993, he joined the legal department of Eni being mostly engaged in international legal activities. Since October 2005, he is the General Counsel and Senior Executive Vice President of Eni. He is a member of the ICC Paris corporate responsibility and anti-corruption commission and since 2011, he participates to the anti-corruption working group of the B20. From 2005 to 2012, he was a non-executive director of Snam Rete Gas[8] a listed Italian company, and in 2012 and 2013, a member of the board of director of Università degli Studi di Bologna. He is the author of numerous publications and teaches corporate responsibility.

Roberto Ulissi was born in Rome in 1962. Lawyer. After a number of years spent as a lawyer at the Bank of Italy, in 1998 he was appointed General Manager at the Ministry of the Economy and Finance, head of the Banking and Financial System and Legal Affairs Department. He was a director of the companies Telecom Italia, Ferrovie dello Stato, Alitalia, Fincantieri and a government representative on the Governing Council of the Bank of Italy. He was also a member of numerous Italian and European committees representing the Ministry of the Economy, including, at a national level, the Commission for the Reform of Corporate Law and, at EU level, the Financial Services Policy Group, the Banking Advisory Committee, the European Banking Committee, the European Securities Committee, and the Financial Services Committee. He was also special professor of banking law at the University of Cassino. He is Grande Ufficiale della Repubblica Italiana. Since 2006 he has been Senior Executive Vice President Corporate Affairs and Governance and Company Secretary of Eni. He is also a director of Eni International BV.

Marco Petracchini was born in Rome in 1964. He graduated Cum Laude in Economics from La Sapienza University in Rome in 1989. After graduation, he was hired by Esso Italiana where he held various positions in the IT, Finance and Auditing sectors. He joined Eni in 1999 in the Internal Audit Department, gradually taking on positions of increasing responsibilities: Head of Downstream Audit activities and Head of Support Process activities (in particular IT and Fraud Audit). He is currently Senior Executive Vice President of the Internal Audit Department. He is also a member of the Watch Structure of Eni SpA and Secretary of the Control and Risk Committee of Eni SpA. He holds international qualifications as well, in detail: Certified Internal Auditor (CIA), Certified Fraud Examiner (CFE), Certified Risk Management Assurance (CRMA). He is currently a Board member of AiiA (Italian Internal Auditors Association).

Marco Alverà graduated from the London School of Economics in 1997 in Philosophy and Economics. He is currently an Associate Fellow at the Oxford University Centre for Corporate Reputation, with particular interest/experience in doing business sustainably in developing economies and in Africa. He started his career at Goldman Sachs in London in 1997 in M&A and Private Equity. In 2000, he co-founded Netesi, Italy s first broadband

ADSL company. From 2002 to 2005, he joined Enel as Head of Group Corporate Strategy before becoming in 2004 Chief Financial Officer of Wind Telecom, overseeing the sale of Wind to Orascom. He joined Eni in 2005 as Assistant to the CEO for special initiatives. In 2006, he was appointed Director of Supply & Portfolio Development at Eni Gas & Power Division and Chief Executive Officer of Blue Stream and Promgas. In 2008, he moved to Eni Exploration & Production Division where he was appointed Executive Vice President for Russia, North Europe and Americas. In these countries he managed operations and led negotiations with governments and other international oil companies. Since 2010, he has been Chief Executive Officer of Eni Trading and Shipping SpA, which manages all the commodity Trading and Shipping activities for Eni. In January 2012, he was appointed Senior Executive Vice President of Eni Trading, that in March 2013, became Eni Optimization & Trading and successively Eni Midstream as of July 2013. The business unit Midstream oversees commodity trading activities, supply and oil & gas portfolio optimization, sales on wholesale Gas & Power markets, Midstream LNG commercial activities and commodities transport. He has served on the Board of Gazprom Neft and is Chairman of the Board of Eni s Russian subsidiaries.

Salvatore Meli was born in Torre del Greco in 1953. After earning his degree in Chemical Engineering, in 1980 he began his career as a researcher, gradually taking on positions of greater responsibility up to 1992, when he became

(8) From January 1, 2012 Snam Rete Gas changed its company name in Snam SpA.

Head of Applied Research in Engineering at Eni Research. In 1998, he became Head of Research of Eni Technologies and took over the responsibility of the entire Department of Engineering, Modeling and Pilot Systems, a position he retained until 2003. In January 2004, he was appointed Head of Planning Technology and Development at Eni Corporate, and then, in August 2006, he took the position of Director of Research and Technological Innovation of the Exploration & Production Division, with the aim of enhancing the role of technological innovation as a leverage in strengthening the competitive position of Exploration & Production business. On January 1, 2008, he was appointed Head of Technologies in Strategic Management and Research at Eni Corporate, with responsibility for monitoring the development of technologies of interest to Eni s activities and to identify development opportunities for new technologies and new energy sources. In this position, particular emphasis was placed on activities enhancing intellectual property through a significant increase in the number and quality of patents filed. On June 10, 2009, as part of Eni Corporate Management Studies and Research, he was appointed Executive Vice President of Research & Technological Innovation; since August 2, 2011, he has been reporting directly to the Chief Executive Officer under the aegis of the Research & Technological Innovation Department.

Leonardo Bellodi was born in Venice in 1965. After graduating in law, he worked at the United Nations and for international law firms. He is the author of numerous publications and has taught international and EU law. In 1998, he was hired as Head of the Eni Delegation at the European Union. Since his return from Brussels in 2006, he has held positions of increasing responsibility at Eni s Department of Public Affairs and Communication, and in 2011 he was appointed as Public Affairs Executive Vice President. Since July 2012, he has been Executive Vice President of Government Affairs, reporting directly to the Chief Executive Officer of Eni SpA. Since 2009, he has also been Chairman of the Board of Directors of Syndial SpA.

Stefano Leofreddi was born in Rome in 1960. He graduated in economics and, after a researcher experience at the International Trade Centre (UN/WTO) in Geneva, he joined Eni in 1986, working in planning and control at EniChem, where he remained until 1998, in positions of increasing responsibility. Then, at Eni Corporate, he has been in charge of important innovating projects in the administration and control area until 2001, when he was appointed Head of Administration and Control at Stogit, where he contributed to the company start-up. Since 2007, returning to Eni Corporate, he coordinated the Eni gas infrastructure functional unbundling program (Snam[9], Italgas, Stogit). From 2009, he was Head of Risk Control and Financial Systems. He is currently Senior Vice President of Integrated Risk Management, reporting directly to the Chief Executive Officer.

Raffaella Leone in Eni since 2005, she is the Executive Assistant to the CEO of Eni. She is President of Servizi Aerei SpA, Vice President of Eni Foundation, member of the Board of Directors of the news agency AGI (Agenzia Giornalistica Italia) and of the Board of Directors of Fondazione Eni Enrico Mattei. Previously, she was the Executive Assistant to the CEOs of Enel (from May 2002 to 2005) and of Pilkington (from 1996 to May 2002).

Compensation

Board members emoluments are determined by the Shareholders Meeting, while the emoluments of the Chairman and CEO, in relation to the powers entrusted to them, are determined by the Board of Directors considering relevant proposals made by the Compensation Committee and after consultation with the Board of Statutory Auditors.

Moreover, in accordance with the applicable Italian laws and regulations (Article 123-*ter* of Legislative Decree No. 58 of February 24, 1998 and Article 84-*quater* of Consob Decision No. 11971 of May 14, 1999, and subsequent modifications) and in line with the Corporate Governance Code recommendations for Italian listed companies, the

Board of Directors approves and submits to the annual Shareholders Meeting advisory vote, the first section of the Remuneration Report which describes the Remuneration Policy Guidelines adopted for Directors, Chief Operating Officers of Eni Division and other Managers with strategic responsibilities[10].

The main elements of the 2014 remuneration policy and of the compensation paid in 2013 to the Chairman, the CEO, other Board members and Eni s Chief Operating Officer and of other Managers with strategic responsibilities, are described below.

(9) As of January 1, 2012, the company name was Snam Rete Gas SpA.

(10) Those persons who have the power and responsibility, directly or indirectly, for planning, directing and controlling Eni fall under the definition of "Managers with strategic responsibilities", pursuant to Consob regulations. Eni Managers with strategic responsibilities, other than Directors and Statutory Auditors, are those who sit on the Management Committee and, in any case, those who report directly to the Chief Executive Officer.

2014 Remuneration Policy Guidelines

The Guidelines for the 2014 Remuneration Policy provide as follows:

- for the Directors in office, whose term ends on the date of the Shareholders Meeting called to approve the financial statements for the year ended December 31, 2013, the 2014 Guidelines reflect the decisions taken by the Board of Directors on June 1, 2011 and do not provide, therefore, significant changes to the Policy already adopted in the previous year;
- for the Directors to be appointed for the new term of office, the main change compared to 2013 is the introduction, subject to approval of the Shareholders Meeting, of the proposed reduction in remuneration in accordance with Article 84-*ter* of the Law No. 98/2013, with a limit to the remuneration of Executive Directors in an amount equal to 75% of the "total remuneration" determined for any reason in the course of the current term of office (defined as the maximum potential remuneration). For the Chief Executive Officer to be appointed after the next renewal of the Board, there will be variable remunerations designed to reward the performance achieved on annual basis, linked to the defined performance metrics for the previous year, and on the medium to long term through the participation in the variable incentive plans provided for the Division Chief Operating Officers and other Managers with strategic responsibilities. For the non-executive Directors who will be part of the Audit and Risk Committee, in relation to the significant and growing engagement required for performing their tasks, the possibility is provided for an increase in the related remuneration, maintaining the criterion of differentiation between the Chairman and other members; and
- for the Division Chief Operating Officers and other Managers with strategic responsibilities, the 2014 Guidelines provide the same compensation instruments defined in 2013, with the adoption of a new Long-term Monetary Incentive Plan for critical managerial resources, which, in replacing the previous one, provides some changes to the performance conditions, in order to ensure greater alignment with shareholder interests and enhance the sustainability of the value creation in the long term, taking into account the guidelines of the proxy advisors and major institutional investors. The Long-term Monetary Incentive Plan for 2014-2016 provides, as performance parameters, both the Total Shareholder Return (TSR) and the Net Present Value (NPV) of proved reserves. The Plan, being also linked to the performance of the Eni stock, will therefore be subject to the approval of the shareholders in their Annual Meeting scheduled for May 8, 2014. The conditions of the Plan will therefore be described in detail in the informative document made available to the public on the Company s website (www.eni.com), in application of current legislation (Article 114-*bis* of Italian Legislative Decree No. 58/1998 and Consob implementing regulations).

CHAIRMAN OF THE BOARD OF DIRECTORS AND NON-EXECUTIVE DIRECTORS

Remuneration of the Chairman for the powers delegated

For the current Chairman, the Board of Directors, on June 1, 2011 defined a supplementary remuneration for the powers delegated in accordance with the Articles of Association, in addition to the remuneration determined by the Shareholders Meeting of May 5, 2011. To this end, a fixed gross annual component of euro 500,000, unchanged from the previous mandate, was established and a variable annual component with a minimum (performance = 85), target (performance = 100) and a maximum incentive level (performance = 130), equal to 51%, 60% and 78%, respectively of the fixed remuneration was established for the delegated powers, to be calculated based on the performance achieved by Eni during the year prior to that in which these are paid. The performance metrics for the incentives that will be paid in 2013 are focused on Eni s economic and financial performance, its operational and industrial performance and on the implementation of the strategic and sustainable guidelines defined in the Strategic Plan, and on specific measures related to the activities of the Chairman to ensure the effective functioning of the Board of Directors.

For the Chairman to be appointed for the new term, the Guidelines for Remuneration Policy, taking into account the specific powers that may be granted in accordance with the Articles of Association and in line with the provisions of Article 84-*ter* of Law No. 98/2013, provide possible compensation for the powers defined within a maximum of 75% of the total remuneration determined for any reason during the current term of office, subject to the approval of the proposal to be presented at the Shareholders   Meeting, and with the performance metrics set in line with the scheme of 2013.

Remuneration of non-executive Directors for participation in Board Committees

For non-executive and/or independent Directors in office, an additional annual remuneration is maintained[11] for their participation in Board Committees, the amounts of which remain unchanged compared with 2013 and are confirmed as follows:

(11) In line with the previous mandate, the Shareholders   Meeting of May 5, 2011 established the remuneration of the Directors providing for: (i) a gross annual fixed remuneration of euro 115,000; and (ii) an annual incentive linked to the positioning of the performance of the Eni stock, compared to the seven major international oil companies by capitalization (Exxon, Shell, Chevron, British Petroleum, Total, Conoco, Statoil). This incentive of euro 20,000 and euro 10,000 is paid if Eni is ranked first and second or third and fourth, respectively, in the afore mentioned rank for the year in question. In all other cases, the incentive is not payable.

- for the Control and Risk Committee, a compensation of euro 45,000 for the Chairman and euro 35,000 for the other members is envisaged, in view of the ever more significant role played by the Committee in monitoring Company risk;
- for the Compensation Committee and the Oil-Gas Energy Committee, the compensation is confirmed at euro 30,000 for the Chairman and euro 20,000 for the other members, as already envisaged in the previous mandate; and
- for participation in the Nomination Committee, established in July 2011, no compensation is envisaged.

Where a Director participates in more than one Committee (with the exception of the Nomination Committee), the compensation due is reduced by 10%.

For non-executive directors who will be appointed for the new mandate, the Guidelines for Remuneration Policy provide, in general, the maintenance of the compensations already defined in 2013 for participation in the Board Committees, and they also confirm the principle of differentiation of remunerations between Chairman and other members, as well as the mechanism of reduction of compensation in case of participation in several committees. For the non-executive Directors who will be part of the Audit and Risk Committee, in relation to the significant and growing engagement required for performing the task, the possibility is provided for an increase in the related remuneration, maintaining the criterion of differentiation between the Chairman and other members.

Payment due in the event of termination of office or employment

No specific payments are envisaged upon the termination of the mandates of Chairman and of non-executive Director nor do any agreements exist that provide for indemnities in the case of the mandate s early termination of the mandate. For the Chairman in office, the Compensation Committee is entitled to propose to the Board of Directors the possible recognition of an indemnity, upon completion of the mandate, commensurate with the compensation received and the achievement of performance of particular relevance to Eni.

Benefits

For the Chairman, the Remuneration Policy Guidelines provide, in line with 2013, insurance-related benefits, also covering the risk of death and disability.

CHIEF EXECUTIVE OFFICER AND GENERAL MANAGER

For the Chief Executive Officer and the General Manager in office, the 2014 remuneration structure reflects the decisions taken by the Board of Directors on June 1, 2011 for the entire duration of the mandate. Remuneration envisaged by the Board in relation to the powers delegated includes both the compensation for Directors determined by the Shareholders Meeting on May 5, 2011, as well as any compensation that may be due for participating in the Board of Directors of Eni s subsidiaries or associated companies. For the Chief Executive Officer to be appointed after the next renewal of the Board, the Remuneration Policy Guidelines provide remuneration defined by taking into account the specific powers to be conferred in accordance with the Articles of Association, within a maximum of 75% of total remuneration determined for the current mandate in accordance with Article 84-*ter* of Law No. 98/2013 and subject to the approval of the proposal that will be presented at the Shareholders Meeting.

Fixed remuneration
For the Chief Executive Officer and the General Manager in office, the fixed remuneration is set at an annual gross amount of euro 1,430,000 of which euro 430,000 is for the role of Chief Executive Officer and euro 1,000,000 is for the role of General Manager; these amounts are unchanged compared to the previous mandate, in consideration of the continuity of the powers granted. In his capacity as Eni Senior Manager, the General Manager is also entitled to receive a travel indemnity, in Italy and abroad, in line with the applicable provisions in the relevant national collective labor agreement for senior managers and complementary Company level agreements.

For the Chief Executive Officer to be appointed after the next renewal of the Board, there are fixed remunerations reformulated in application of the proposal that will be presented at the Shareholders Meeting under the afore mentioned Law No. 98/2013, also taking into account the specific powers that will be awarded in accordance with the Articles of Association, as well as the recommendations contained in the principles and general purposes of Eni s Remuneration Policy.

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Annual variable incentives

For the Chief Executive Officer and the General Manager in office, in line with 2013, the 2014 annual variable incentive plan is linked to the achievement of the predefined performance metrics from the previous year, measured according to a performance scale of 70÷130, in relation to the weight assigned to each objective (below 70 points, the performance of each objective is considered zero). For the purposes of the incentive, the minimum overall performance is 85 points. The 2013 performance metrics for the purpose of incentives that will be paid in 2014 have concerned in particular: (i) the implementation of the lines of strategic and financial sustainability (weight 30%) in terms of reserve replacement, increase in exploration resources, optimization of productive and financial activities, maintenance of Eni s presence in the indexes "FTSE4Good" and "Dow Jones Sustainability Index"; (ii) the adjusted EBIT (weight 30%); (iii) the operating performance of the Divisions (weight 30%); and (iv) the efficiency program (weight 10%). The annual variable incentive plan for the Chief Executive Officer and the General Manager envisages compensation tied to a minimum (performance = 85), a target (performance = 100) and a maximum incentive level (performance = 130), set at 87.5%, 110% and 155%, respectively of the total fixed remuneration, based on the results achieved by Eni in the previous year.

Long-term variable incentives

For the Chief Executive Officer and General Manager in office, the long-term residual variable component for 2014 regards the third and final allocation of the Deferred Monetary Incentive Plan, also provided for all executives of the Company and linked to the performance of the Company measured in terms of EBITDA. This parameter is generally used in the oil and gas sector as a performance indicator and is in line with Eni s growth and consolidation strategy in its various areas of business. The assignment and payment of the incentive, after a three-year vesting period, are subject to the following conditions: (i) the incentive to be assigned is determined in relation to the EBITDA results achieved by the Company during the previous year, measured on a performance scale 70÷130, with respective minimum, target and maximum values of 38.5%, 55% and 71.5% of the total fixed remuneration. If the results are below the minimum level of performance, no allocation is made; (ii) the incentive to be paid at the end of the three-year vesting period is determined on the basis of the average annual EBITDA results achieved during the vesting period, as a percentage between zero and 170% of the assigned value. The annual performance is evaluated on a scale of between 70% and 170% (below the minimum threshold of 70%, the performance is assumed to be zero). Should the current office not be renewed, the payment of each incentive assigned will occur at the natural expiry of the relative vesting period, in accordance with the performance conditions defined in the Plan. For the Chief Executive Officer and General Manager in office, the Board of Directors also approved, on September 19, 2013 the third and final allocation of the Long-Term Monetary Incentive Plan introduced to replace the previous Stock Option Plan, no longer operating since 2009.

For the Chief Executive Officer to be appointed after the next renewal of the Board, there will be variable remunerations designed to reward the performance achieved on an annual basis, linked to the defined performance metrics for the previous year, and in the medium to long-term period through the participation in the variable incentive plans provided for the Division Chief Operating Officers and other Managers with strategic responsibilities. The Chief Executive Officer will therefore participate in the Long-Term Monetary Incentive Plan for critical managerial resources linked to two new performance benchmarks (Total Shareholder Return and Net Present Value of proved reserves), measured in relative terms compared to a reference peer group over three years, according to the characteristics more fully described under the section *"Chief Operating Officers of Eni s Divisions and other Managers with strategic responsibilities Long-term variable incentives".* Should the current office not be renewed, the payment of each incentive assigned will occur at the natural expiry of the relative vesting period, in accordance with the performance conditions defined in the Plan. The maximum limits of the components of the variable incentive will be determined within the constraints of remunerations reductions required by Law No. 98/2013 and taking into account the recommendations contained in the principles and general purposes of Eni s Remuneration Policy.

On the basis of the February 12, 2014, Board resolution, the 2014 performance metrics linked to the short-term incentive plan of the Chief Executive Officer concern in particular: (i) the business results, in terms of free cash flow and adjusted EBIT (total weight 40%); (ii) the implementation of the strategic guidelines (weight 30%) in terms of reserve replacement, increase in exploration resources, optimization of production activities and financial structure; and (iii) the operating performance of the Divisions (weight 20%); sustainability (weight 10%), in relation to the maintenance of Eni s presence in at least one of the indexes "FTSE4Good" and "Dow Jones Sustainability Index" and the development of the "Integrity Culture" program.

Treatments established in the event of termination of office or employment

The following is envisaged for the Chief Executive Officer and General Manager in office in accordance with the practices in the markets of reference and in line with the previous mandate, also considering the entitlements already accrued within the employment relationship, established before March 31, 2010 and due to which, in accordance with the Corporate Governance Code, the recommendations pursuant to criteria 6.C.1, letter f) of the same code cannot be applied:

upon termination of the management employment relationship, either in expiry or due to early termination of the current mandate, an indemnity is envisaged in addition to the severance pay due upon termination of employment and in lieu of any obligations regarding prior notice. This is defined as a fixed component of euro 3,200,000 and a variable component based on the value of the annual variable incentive calculated with respect to the average of Eni performance in the three-year period 2011-2013; the indemnity will not be due should the termination of the employment relationship meet the requirements of due cause, or occur as the result of death or of the party s resignation from office for reasons other than an essential reduction of the powers currently attributed;

at the end of the mandate a payment will be recognized which, in relation to the fixed remuneration and 50% of the maximum variable remuneration earned for the administrative role alone, will guarantee a social security contribution and severance pay equal to that paid by Eni for the management employment relationship; and

in relation to the undertaking assumed by the Chief Executive Officer and General Manager not to carry out any type of activity that may be in competition with that performed by Eni for a period of one year after the termination of the employment relationship, in all of Italy, Europe and North America, the payment of euro 2,219,000 is envisaged.

Moreover the Committee is entitled to propose to the Board, upon the conclusion of the mandate, a possible increase in the amounts due upon termination of office, in case notable results have been achieved over the course of the three-year period.

For the Chief Executive Officer to be appointed after the next renewal of the Board without prejudice to the acquired rights linked to any continuation of the appointments and contracts in progress at the date of approval of this Report the 2014 Remuneration Policy Guidelines provide for the possibility:

of recognizing possible severance indemnity in line with the recommendations of the Corporate Governance Code and to an extent not exceeding two years remuneration; and

to stipulate possible non-competition agreements, with specific consideration in relation to the annual remuneration, as well as in relation to the nature, extent and duration of these commitments.

Benefits

In line with the previous mandate and the policy implemented in 2013, the Policy Guidelines provide for insurance-related benefits, including for the risk of death or disability. In particular, and in compliance with what is provided in the national collective labor agreement and the complementary company level agreements for Eni senior managers, enrolment in the supplementary pension plan (FOPDIRE[12]), as well as in the complementary health plan (FISDE[13]) are also provided, together with the use of a Company car. For the Chief Executive Officer to be appointed after the next renewal of the Board, the 2014 Guidelines provide for equivalent types of benefits.

CHIEF OPERATING OFFICERS OF ENI S DIVISIONS AND OTHER MANAGERS WITH STRATEGIC RESPONSIBILITIES

Fixed remuneration

The fixed remuneration is based on the role and the responsibilities assigned, and takes into consideration the average compensation paid in large national and international companies for similar roles, responsibilities and complexity. It may be updated periodically in the context of the annual salary review that involves all managerial resources. The 2014 Guidelines, in consideration of the context of reference and current market trends, provide for selective criteria, while maintaining appropriate levels for competitiveness and motivation. In particular, the proposed actions will include: (i) actions to adapt the fixed pay for people who fulfil roles that have seen an increase in responsibility or who fall below the average for the reference market; and (ii) one-time extraordinary payments for those who have achieved results or completed projects of particular significance during the year, to promote the achievement of a performance far superior to the targets assigned. In addition, as an Eni Senior Manager, the Chief Operating Officers of Eni s Divisions and the other Managers with strategic responsibilities are entitled to receive the travel indemnities, in Italy and abroad, in line with the applicable provisions in the relevant national collective labour agreement for senior managers and in the complementary Company level agreements.

Annual variable incentives

The annual variable incentive plan provides for remuneration to be awarded in 2014, calculated with reference to the Eni s performance results, for the business areas and individuals, achieved in the previous year and measured in accordance with a performance scale of 70÷130 with a minimum incentive level equal to 85 points, below which no

(12) Defined contribution retirement plan with individual capitalization, www.fopdire.it.
(13) Plan which disburses reimbursement of health expenses for working and retired directors and their families, www.fisde-eni.it.

incentive is due, as has already been described for the Chief Executive Officer and General Manager. The target incentive level (performance = 100) differs by up to a maximum of 60% of the fixed remuneration, based on the role. For each business area, the performance metrics of the Chief Operating Officers and Managers with strategic responsibilities are determined on the basis of those assigned to the Chief Executive Officer and are focused, for each business area, on the economic and financial, operational and industrial performance, on internal efficiency and issues of sustainability (in terms of health and safety, environmental protection, relations with stakeholders), as well as on individually assigned targets in relation to the areas of responsibility of the role held, in accordance with the Strategic Plan of the Company.

Long-term variable incentives

The Chief Operating Officers and the other Managers with strategic responsibilities participate in the Long-Term Incentive Plans approved by the Board of Directors on March 15, 2012 and March 17, 2014, consisting of:

a Deferred Monetary Incentive Plan designed for the managerial resources who have delivered the performance results established in the annual variable incentive Plan. The 2012-2014 Plan envisages three annual assignments, as of 2012, with the same performance conditions and characteristics as those described above for the Chief Executive Officer and General Manager. For the Chief Operating Officers and the other Managers with strategic responsibilities, the incentive to be assigned each year is determined in relation to the EBITDA results achieved by the Company in the previous year, measured on a performance scale of 70÷130. The target incentive level differs, based on the role, by up to a maximum of 40% of the fixed remuneration. The incentive to be paid at the end of the three-year vesting period is determined on the basis of the average annual EBITDA results achieved during the three-year period, as a percentage between zero and 170% of the assigned value; and

a Long-Term Monetary Plan envisaged for the managerial resources who are critical for the business. The 2014-2016 Plan, subject to approval by the Shareholder s Meeting, will replace, with respect to the last allocation, the previous 2012-2014 Plan. The new plan includes three annual allocations, starting from 2014, with partially different conditions from the previous Plan, in relation to a need for greater alignment of this form of incentive to the interests of shareholders and the sustainability of growth in the long term. To this end, the new plan provides for the introduction of two new performance benchmarks (Total Shareholder Return[14] and Net Present Value of proved reserves[15]), measured in relative terms compared to a peer group of reference, over a period of three years. The conditions of the Plan include, in particular: (i) incentive to be given to targets differentiated by role level up to a maximum of 75% of the fixed remuneration; and (ii) incentive to be paid at the end of the three-year vesting determined in relation to the results achieved in terms of variation of the parameters identified (TSR with a weight of 60% and NPV with a weight of 40%) in the three-year period in question in relative terms compared to a peer group consisting of the following international oil companies: Exxon, Chevron, Shell, British Petroleum, Total, Repsol. The amount to be paid is defined as a percentage of the amount assigned according to the average annual placements achieved in the vesting period, compared with those achieved by the companies in the peer group according to the following scale: 1st place = 130%; 2nd place = 115%; 3rd place = 100%; 4th place = 85%; 5th place = 70%; 6th and 7th place = 0%. The minimum incentive threshold involves reaching 5th place for both indicators in at least one year of the three-year vesting period.

Both Plans include clauses aimed at promoting employee retention, envisaging, in the case of consensual contract resolution or transfer and/or loss of control on the part of Eni of the company of which the individual in question is an employee during the course of the vesting period, that the employee in question maintains the right to the incentive decreased in measure related to the period between assignment of the basic incentive and the occurrence of said events. No payment is envisaged in the case of unilateral termination.

Payment due in the event of termination of office or employment

For Chief Operating Officers and other Managers with strategic responsibilities, as for Eni senior manager, the payment due for employment termination as per the relevant national collective labor agreement is envisaged, together with any other additional severance indemnity agreed upon on an individual basis upon termination, according to the criteria established by Eni for cases of early resolution and/or retirement. These criteria take into account the retirement age and the actual age of the manager at the time when the employment is terminated and the annual remuneration received. Specific compensation for cases in which it is necessary to stipulate non-competition agreements may also be envisaged.

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(14) The Total Shareholder Return (TSR) is an indicator that measures the overall return of a stock investment, taking into consideration both the price change and the dividends paid and reinvested in the same stock, in a specific period.

(15) The Net Present Value is an indicator that represents the present value of the future cash flows of proved hydrocarbon reserves, net of future production and development costs and related taxes. It is calculated on the basis of standard references defined by the Securities Exchange Commission on the basis of the data published by the oil companies in the official documentation (Form 10-K and Form 20-F).

Benefits
For the Chief Operating Officers and other Managers with strategic responsibilities, as per the policy implemented in 2013, insurance-related benefits are envisaged and, in particular, in compliance with that envisaged in the National collective labor agreement and the complementary company level agreements for Eni senior managers, enrolment in the FOPDIRE plan, as well as in the FISDE plan are also envisaged, together with the use of a company car.

MARKET REFERENCES AND PAY MIX

The reference markets used for remuneration benchmarks are: (i) for the Chairman and the Chief Executive Officer and General Manager, similar roles in the main international companies in the Oil sector, as well as in the largest national and European listed companies of greatest capitalization; (ii) for non-executive Directors, similar roles in the largest national listed companies of greatest capitalization; and (iii) for the Chief Operating Officers and other Managers with strategic responsibilities, roles with the same level of responsibility and managerial complexity in large national and international industrial companies.

The 2014 Remuneration Policy Guidelines lead to a remuneration mix in line with the management positions held, with greater weight given to the variable component, in particular over the long term, for those position having a greater impact on Company results.

Compensation and other information

IMPLEMENTATION OF THE 2013 REMUNERATION POLICIES

The description below outlines the implementation of the 2013 remuneration policies with respect to the Chairman of the Board of Directors, non-executive Directors, Chief Executive Officer and General Manager, Chief Operating Officers of Eni s Divisions, and other Managers with strategic responsibilities. The implementation of the 2013 Remuneration Policy, as verified by the Compensation Committee at the time of periodic evaluation required by the Corporate Governance Code, remained consistent with the 2013 Remuneration Policy, approved by the Board of Directors on March 14, 2013, as well as with the market references found, both in terms of overall positioning and of pay-mix.

Fixed remuneration
The agreed fixed remuneration was paid to the Chairman, in relation to the role and the powers delegated to the same, respectively at the Shareholders Meeting of May 5, 2011 and the Board of Directors of June 1, 2011, in line with the remuneration structure and the amounts defined in the previous mandate. Fixed compensation was paid to the non-executive Directors as approved by the Shareholders Meeting of May 5, 2011 and these remained unchanged with regard to the previous mandate. The fixed remuneration was paid to the Chief Executive Officer and General Manager, as approved by the Board of Directors on June 1, 2011 which left the structure and amounts as the previous mandate due to the continuity of the delegated powers and the responsibilities entrusted to the Chief Executive Officer and General Manager. This remuneration included the compensation approved by the Shareholders Meeting for the Directors. For the Chief Operating Officers of Eni s Divisions and the other Managers with strategic responsibilities, within the context of the annual salary review process envisaged for all managers, selective adjustments were made to fixed remuneration in 2013, in cases of promotion to superior levels, or in relation to the necessity to adjust

remuneration levels with respect to the market references identified.

Remuneration for participation in Board Committees
Non-executive Directors receive additional compensation for their participation in Board Committees, in accordance with that determined by the Board of Directors on June 1, 2011.

Variable incentives

Shareholders Meeting variable compensation for the Chairman and the non-executive Directors
In 2013, as verified by the Board of Directors on March 14, 2013, on a proposal by the Compensation Committee, the conditions required in order to pay the variable component of the compensation approved by the Shareholders Meeting of May 5, 2011 to the Chairman and the non-executive Directors, were met. The results for the total 2012 return of the Eni stock compared with that of the other seven major international oil companies by capitalization did in

fact place Eni at the top of the ranking, resulting in the payment of an amount of euro 80,000 for the Chairman and euro 20,000 for the other non-executive Directors.

Annual variable incentives

The 2013 annual incentive was paid, with respect to the top managerial positions, given the actual results on the performance metrics set for 2012 in line with the Strategic Plan and the annual budget, in terms of: (i) the implementation of the strategic and financial sustainability guidelines, taking into account the assessment expressed by the Compensation Committee on the targets achieved in terms of reserve replacement and increase in exploration resources, optimization of operational activities in the Refining & Marketing sector and in Chemicals, financial leverage, maintenance of Eni s listing in the main sustainability indexes; (ii) operating performance of the Divisions; (iii) adjusted EBIT; and (iv) efficiency program. Eni s results in 2012, evaluated using a constant scenario approved by the Board at the Meeting of March 14, 2013 and following a proposal by the Compensation Committee, led to a performance score of 124 points in the measurement scale used, which respectively envisaged target and maximum performance levels of 100 and 130 points. With regard to the Chief Operating Officers of Eni s Divisions, the incentive was paid based on the economic and operational performance obtained in their respective business sectors, also taking into account an evaluation of how well specific sustainability measures had been achieved (in terms of health and safety, environmental protection and relations with stakeholders). For the other Managers with strategic responsibilities, the variable incentive paid in 2013 was linked to the Company results and to a series of individual targets assigned in relation to the area of responsibility of the role held, in line with that envisaged in the Eni 2012 Performance Plan. For the purposes of the variable remuneration to be paid in 2013, assessed performance results were as follows:

- for the Chairman, the payment of a bonus equal to 74.4% of the fixed remuneration, taking into account the target (60%) and maximum (78%) incentive levels assigned;
- for the Chief Executive Officer, the payment of a bonus equal to 146% of the fixed remuneration, taking into account the target (110%) and maximum (155%) incentive levels assigned; and
- for the Chief Operating Officers of Eni s Divisions and the Managers with strategic responsibilities, the payment of bonuses determined in relation to the specific performance achieved, in accordance with the incentive levels differentiated by role.

Deferred Monetary Incentive Plan

At its meeting on March 14, 2013, the Board of Directors, as verified and proposed by the Compensation Committee, determined that the 2012 EBITDA result (evaluated using a constant scenario) had achieved the target level. Therefore, for the Chief Executive Officer and General Manager, the Board ruled to assign an incentive for 2013 equal to euro 786,500 (55% of the fixed remuneration). For Chief Operating Officers and the other Managers with strategic responsibilities, the incentive amounts defined at target level were assigned, differentiated by role up to a maximum of 40% of the fixed remuneration. In addition, in 2013 the Deferred Monetary Incentive assigned in 2010 to the Chief Executive Officer and General Manager, to Chief Operating Officers of Eni s Divisions, and to other Managers with strategic responsibilities reached maturity. At its meeting on March 14, 2013, based on Eni s EBITDA results during the 2010-2012 period, and on the proposal forwarded by the Compensation Committee, the Board of Directors approved the multiplier to be applied to the amount assigned, for the purposes of calculating the amount to be paid. This was determined at 130%. As a result, an incentive of euro 1,022,450 was paid to the Chief Executive Officer (equal to 130% of the base incentive of euro 786,500 assigned in 2010).

Long-Term Monetary Incentive Plan

At its meeting on September 20, 2012, the Board of Directors, based on a check and proposal by the Compensation

Committee, resolved the allocation to the Chief Executive Officer and General Manager of the 2013 base incentive from the Long-Term Monetary Incentive Plan provided by the Board resolution of June 1, 2011 replacing the previous stock-option plan, which had not been implemented since 2009. The amount of the incentive assigned was defined at euro 2,251,974 in accordance with the criteria and the valuation methods approved by the Board and with the assistance of specialized external consultants. For the Chief Operating Officers of Eni s Divisions and the other Managers with strategic responsibilities, the amounts were determined in accordance with the target incentive level, differentiated by role up to a maximum of 50% of the fixed remuneration. In addition, in 2013 the Deferred Monetary Incentive assigned in 2010 to the Chief Executive Officer and General Manager, to Division Chief Operating Officers, and to other Managers with strategic responsibilities reached maturity. The Board of Directors, at its meeting of March 14, 2013, on the basis of the results related to the variation of Adjusted Net Profit + DD&A achieved in the period 2010-2012 and the annual placements with the peer group compared to the base year of reference (2009), has verified, as proposed by the Compensation Committee, the absence of the conditions for granting such an incentive.

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Severance indemnity for end of office or termination of employment
In the course of 2013, no severance indemnity for end of office was approved for and/or paid to the Directors, Division Chief Operating Officers and other Managers with strategic responsibilities.

COMPENSATION PAID IN 2013

The individual amounts of compensation paid in 2013 to each member of the Board of Directors, to Chief Operating Officers and to each member of the Board of Statutory Auditors, as well as the overall amounts paid to other Managers with strategic responsibilities, are reported in the table below, pursuant to Article 84-*quater* of Consob Decision No. 11971 of May 14, 1999, and subsequent modifications.

In particular:

- the column "Fixed remuneration" reports the amounts accrued through profit and loss of fixed remuneration and fixed salary from employment due for the year, gross of social security and tax expenses to be paid by the employee; it excludes attendance fees, as they are not envisaged. Details on compensation are provided in the notes, as well as separate indication of any indemnities or payments referred to the employment relationship;
- the column "Committee membership remuneration" reports, following the criteria of competence, the compensation due to the Directors for participation in the Committees established by the Board. In the notes, compensation for each Committee on which each Director participates is indicated separately;
- the column "Variable non-equity remuneration - Bonuses and other incentives" reports the incentives paid during the year due to rights vested following the assessment and approval of the relative performance results by the relevant Company bodies, in accordance with that specified, in greater detail, in the Table of page 150 on monetary incentive plans for Directors, Chief Operating Officers, and other Managers with strategic responsibilities;
- the column "Profit sharing", does not include any figures, as no form of profit-sharing is envisaged;
- the column "Non-monetary benefits" reports, in accordance with competence and taxability criteria, the value of fringe benefits awarded;
- the column "Other remuneration" reports, in accordance with the criteria of competence, any other remuneration deriving from other services provided;
- the column "Total" reports the sum of the amounts of all the previous items;
- the column "Fair value of equity remuneration" reports the fair value of competence of the year related to the existing stock option plans, estimated in accordance with international accounting standards which assign the relevant cost in the vesting period; and
- the column "Severance indemnities for end of office or termination of employment" reports the indemnities accrued, even if not yet paid, for the terminations which occurred during the course of financial year considered or in relation to the end of the office and/or employment.

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Remuneration paid to Directors, Statutory Auditors, Chief Operating Officers and other Managers with strategic responsibilities

(euro thousand)								Variable non-equity remuneration						
Name	**Notes**	**Office**	**Term of office**	**Office expiry (*)**	**Fixed remuneration**	**Committee membership remuneration**	**Bonuses and other incentives**	**Profit sharing**	**Non-monetary benefits**	**Other remuneration**	**Total 2013**	**Fair value of equity remuneration**	**Severance indemnity for end of office or termination of employment**
Board of Directors													
Giuseppe Recchi	(1)	Chairman	01.01-12.31	04.2014	765 (a)		452 (b)		4		1,221		
Paolo Scaroni	(2)	CEO and General Manager	01.01-12.31	04.2014	1,430 (a)		3,110 (b)		15		4,555		
Carlo Cesare Gatto	(3)	Director	01.01-12.31	04.2014	115 (a)	50 (b)	20 (c)				185		
Alessandro Lorenzi	(4)	Director	01.01-12.31	04.2014	115 (a)	59 (b)	20 (c)				194		
Paolo Marchioni	(5)	Director	01.01-12.31	04.2014	115 (a)	50 (b)	20 (c)				185		
Roberto Petri	(6)	Director	01.01-12.31	04.2014	115 (a)	36 (b)	20 (c)				171		
Alessandro Profumo	(7)	Director	01.01-12.31	04.2014	115 (a)	45 (b)	20 (c)				180		
Mario Resca	(8)	Director	01.01-12.31	04.2014	115 (a)	45 (b)	20 (c)				180		
Francesco Taranto	(9)	Director	01.01-12.31	04.2014	115 (a)	50 (b)	20 (c)				185		
Board of Statutory Auditors													
Ugo Marinelli	(10)	Chairman	01.01-12.31	04.2014	115 (a)						115		
Francesco Bilotti	(11)	Auditor	09.05-12.31	04.2014	26 (a)						26		
Roberto Ferranti	(12)	Auditor	01.01-09.04		54 (a)						54		
Paolo Fumagalli	(13)	Auditor	01.01-12.31	04.2014	80 (a)						80		
Renato Righetti	(14)	Auditor	01.01-12.31	04.2014	80 (a)						80		
Giorgio Silva	(15)	Auditor	01.01-12.31	04.2014	80 (a)						80		
Chief Operating Officers													
Claudio Descalzi	(16)	E&P Division	01.01-12.31										
Remuneration in the company preparing the financial statements					774 (a)		1,495 (b)		13		2,282		
Remuneration from subsidiaries and associates										606 (c)	606		
				Total	774		1,495		13	606	2,888		
Angelo Fanelli	(17)	R&M Division	01.01-12.31		585 (a)		651 (b)		14		1,250		
Other Managers with strategic responsibilities	(18)	*Remuneration in the company preparing the financial statements*			5,289		5,117		144	120	10,670		
					294		289			105	688		

(**)	*Remuneration from subsidiaries and associates*								
	Total	5,583 (a)		5,406 (b)	144	225 (c)	11,358		
		10,377	**335**	**11,254**	**190**	**831**	**22,987**		

Notes
(*) The term of office expires with the Shareholders Meeting approving the Financial Statements for the year ending December 31, 2013.
(**) Managers who were permanent members of the Company s Management Committee, during the course of the year together with the Chief Executive Officer and Division Chief Operating Officers, and those who report directly to the Chief Executive Officer (twelve managers).
(1) **Giuseppe Recchi - Chairman of the Board of Directors**
(a) The amount includes the fixed remuneration of euro 265 thousand established by the Shareholders Meeting on May 5, 2011 and the fixed remuneration of euro 500 thousand for the powers granted by the Board of Directors on June 1, 2011.
(b) The amount includes the payment of euro 80 thousand relating to the variable remuneration approved by the Shareholders Meeting of May 5, 2011 and euro 372 thousand relating to the annual variable incentive.
(2) **Paolo Scaroni - Chief Executive Officer and General Manager**
(a) The amount includes the fixed remuneration of euro 430 thousand for the role of Chief Executive Officer (which incorporates the remuneration established by the Shareholders Meeting on May 5, 2011 for the role of Director) and the fixed remuneration of euro 1 million for the role of General Manager; indemnity due for transfers, in Italy and abroad, in line with the provisions of the relevant national collective labor agreement for senior managers and of the other Company s agreements are added to this amount for a total of euro 142 thousand.
(b) The amount includes the variable annual incentive of euro 2,088 thousand, and the deferred monetary incentive of euro 1,022 thousand awarded in 2010 and paid in 2013.
(3) **Carlo Cesare Gatto - Director**
(a) The amount corresponds with the fixed annual remuneration that was not changed by the Shareholders Meeting of May 5, 2011.
(b) The amount includes euro 31.5 thousand for participation in the Control and Risk Committee and euro 18 thousand for the Compensation Committee.
(c) The amount corresponds to the variable remuneration approved by the Shareholders Meeting May 5, 2011.
(4) **Alessandro Lorenzi - Director**
(a) The amount corresponds with the fixed annual remuneration that was not changed by the Shareholders Meeting of May 5, 2011.
(b) The amount includes euro 40.5 thousand for participation in the Control and Risk Committee and euro 18 thousand for the Oil-Gas Energy Committee.
(c) The amount corresponds to the variable remuneration approved by the Shareholders Meeting May 5, 2011.
(5) **Paolo Marchioni - Director**
(a) The amount corresponds with the fixed annual remuneration that was not changed by the Shareholders Meeting of May 5, 2011.
(b) The amount includes euro 31.5 thousand for participation in the Control and Risk Committee and euro 18 thousand for the Oil-Gas Energy Committee.
(c) The amount corresponds to the variable remuneration approved by the Shareholders Meeting May 5, 2011.
(6) **Roberto Petri - Director**
(a) The amount corresponds with the fixed annual remuneration that was not changed by the Shareholders Meeting of May 5, 2011.
(b) The amount includes euro 18 thousand for participation in the Compensation Committee and euro 18 thousand for the Oil-Gas Energy Committee.
(c) The amount corresponds to the variable remuneration approved by the Shareholders Meeting May 5, 2011.
(7) **Alessandro Profumo - Director**
(a) The amount corresponds with the fixed annual remuneration that was not changed by the Shareholders Meeting of May 5, 2011.
(b) The amount includes euro 18 thousand for participation in the Compensation Committee and euro 27 thousand for the Oil-Gas Energy Committee.
(c) The amount corresponds to the variable remuneration approved by the Shareholders Meeting May 5, 2011.
(8) **Mario Resca - Director**
(a) The amount corresponds with the fixed annual remuneration that was not changed by the Shareholders Meeting of May 5, 2011.
(b) The amount includes euro 27 thousand for participation in the Compensation Committee and euro 18 thousand for the Oil-Gas Energy Committee.
(c) The amount corresponds to the variable remuneration approved by the Shareholders Meeting May 5, 2011.
(9) **Francesco Taranto - Director**
(a) The amount corresponds with the fixed annual remuneration that was not changed by the Shareholders Meeting of May 5, 2011.
(b) The amount includes euro 31.5 thousand for participation in the Control and Risk Committee and euro 18 thousand for the Oil-Gas Energy Committee.
(c) The amount corresponds to the variable remuneration approved by the Shareholders Meeting May 5, 2011.
(10) **Ugo Marinelli - Chairman of the Board of Statutory Auditors**
(a) The amount corresponds with the fixed annual remuneration that was not changed by the Shareholders Meeting of May 5, 2011.

(11) **Francesco Bilotti - Statutory Auditor**
(a) The amount corresponds to the pro-rata from September 5 of the fixed annual remuneration that was not changed by the Shareholders Meeting of May 5, 2011.

(12) **Roberto Ferranti - Statutory Auditor**
(a) The amount corresponds to the pro-rata up to September 4 of the fixed annual remuneration which was not changed by the Shareholders Meeting of May 5, 2011, entirely paid to the Ministry of Economy and Finance.

(13) **Paolo Fumagalli - Statutory Auditor**
(a) The amount corresponds with the fixed annual remuneration that was not changed by the Shareholders Meeting of May 5, 2011.

(14) **Renato Righetti - Statutory Auditor**
(a) The amount corresponds with the fixed annual remuneration that was not changed by the Shareholders Meeting of May 5, 2011.

(15) **Giorgio Silva - Statutory Auditor**
(a) The amount corresponds with the fixed annual remuneration that was not changed by the Shareholders Meeting of May 5, 2011.

(16) **Claudio Descalzi - Chief Operating Officer E&P Division**
(a) To the amount of euro 774 thousand as gross annual salary are added the indemnities owed for the travel performed, in Italy and abroad, in line with the provisions of the relevant national collective labor agreement for senior managers and the Company s additional agreements, as well as other indemnities ascribable to the employment relationship, for a total amount of euro 352 thousand.
(b) The amount includes the payment of euro 357 thousand relating the deferred monetary incentive assigned in 2010.
(c) Amount relating to remuneration for the Chairman of Eni UK.

(17) **Angelo Fanelli - Chief Operating Officer R&M Division**
(a) To the amount of euro 585 thousand as gross annual salary are added the indemnities owed for the travel performed, in Italy and abroad, in line with the provisions of the relevant national collective labor agreement for senior managers and the Company s additional agreements, as well as other indemnities ascribable to the employment contract, for a total amount of euro 101 thousand.
(b) The amount includes the payment of euro 164 thousand relating the deferred monetary incentive assigned in 2010.

(18) **Other Managers with strategic responsibilities**
(a) To the amount of euro 5,583 thousand as gross annual salary, as the indemnities owed for the transfers performed, in Italy and abroad, in line with the provisions of the relevant national collective labor agreement for senior managers and with the Company s additional agreements, as well as other indemnities related to the employment contract for a total amount of euro 766 thousand.
(b) The amount includes the payment of euro 1,446 thousand relating the deferred monetary incentives awarded in 2010.
(c) Relating to the positions held by Managers with strategic responsibilities in the Supervisory Body established pursuant to the Company s Model 231, to the role of manager responsible for the preparation of the Company s financial statements and to the compensation received for positions held in subsidiaries or associated companies of Eni.

OTHER INFORMATION

Accrued compensation

Total compensation accrued in the year 2013 pertaining to all the Board members amounted to euro 13.4 million; it amounted to euro 0.474 million in the case of the Statutory Auditors. Such amounts include, in addition to each item of emolument reported in the table above, amounts accrued in the year for pension benefits, social security contributions and other elements of the remuneration associated with roles performed, which represent a cost for the Company.

For the year ended December 31, 2013, remuneration of persons in key positions in planning, direction and control functions of Eni Group companies, including executive and non-executive Directors, Chief Operating Officers and other Managers with strategic responsibilities amounted to euro 38 million and was accrued in Eni s Consolidated Financial Statements for the year ended December 31, 2013. The breakdown is as follow:

	2013
	(euro million)
Fees and salaries	25
Post employment benefits	2
Other long-term benefits	11
	38

The above amounts include salaries, fees for attending meetings, lump-sum amounts paid in lieu of expense reimbursements, stock-based compensation and other deferred incentive bonuses, health and pension contributions and amounts accrued to the reserve for employee termination indemnities, which is used to pay severance pay as required by Italian law to employees upon termination of employment. The members of the Board of Directors in their capacity as such are not entitled to receive such severance pay. As of December 31, 2013, the total amount accrued to the reserve for employee termination indemnities with respect to members of the Board of Directors who were also employees of Eni, the three Divisional Chief Operating Officers and Eni s senior managers was euro 1,562 thousand.

Name		**(euro thousand)**
Paolo Scaroni	CEO and General Manager of Eni	185
Claudio Descalzi	Chief Operating Officer of the E&P Division	338
Angelo Fanelli	Chief Operating Officer of the R&M Division	244
Senior managers [(a)]		795
		1,562

(a) No. 12 managers.

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Stock options

The Company discontinued any stock-based compensation scheme in 2009; as such, options outstanding as of the end of the year pertained to stock options schemes adopted in previous reporting periods. At December 31, 2013, a total of 2,980,725 options were outstanding for the purchase of an equal amount of Eni ordinary shares without nominal value.

The following table shows the evolution of stock option activity in 2012 and 2013.

	2012			2013		
	Number of shares	**Weighted average exercise price** (euro)	**Market price** (euro)	**Number of shares**	**Weighted average exercise price** (euro)	**Market price** (euro)
Options as of January 1	**11,873,205**	**23.101**	**15.941**	**8,259,520**	**23.545**	**18.457**
Options exercised in the period	(93,000)	16.576	16.873	-	-	-
Options cancelled in the period	(3,520,685)	22.233	16.637	(5,278,795)	24.112	16.278
Options outstanding as of December 31	**8,259,520**	**23.545**	**18.457**	**2,980,725**	**22.540**	**17.533**
of which exercisable as of December 31	**8,243,205**	**23.544**	**18.457**	**2,969,450**	**22.540**	**17.533**

Pursuant to Article 84-*quater* of Consob Decision No. 11971 of May 14, 1999, and subsequent modifications, the table below indicates, by name, the stock options assigned to the Chief Executive Officer and General Manager, to the Chief Operating Officers of the Divisions and, at an aggregate level, to other Managers with strategic responsibilities (including all those individuals who, during the course of the 2013 period, filled said roles, even if only for a fraction of the year).

In particular, the purchase rights (options) for Eni shares or for subsidiaries, which can be exercised after three years from the date granted are indicated, in relation to the existing stock incentive plans, the last of which was granted in 2008. The data are shown in accordance with the criteria of aggregate representation, as these are incentive plans which are now only residual.

Stock options granted to Directors, Chief Operating Officers and other Managers with strategic responsibilities

	Name	**Paolo Scaroni**	**Claudio Descalzi**	**Angelo Fanelli**	**Other Managers with strategic responsibilities** (1)
	Office	**CEO and General Manager**	**Chief Operating Officer of E&P Division**	**Chief Operating Officer of R&M Division**	
	Plan	Eni Stock Option Plans	Eni Stock Option Plans	Eni Stock Option Plans	Eni Stock Option Plans
Options held at the start of the year					
Number of options		1,288,635	108,635	54,910	597,810
Average exercise price	(euro)	23.440	23.869	23.866	23.879
Average maturity	(months)	10	12	13	13

Options granted during the year					
Number of options					
Exercise price	(euro)				
Period of possible exercise	(from-to)				
Fair value on grant date	(euro)				
Grant date					
Market price of underlying shares upon granting of options	(euro)				
Options exercised during the year					
Number of options					
Exercise price	(euro)				
Market price of underlying shares on exercise date	(euro)				
Options expired during the year					
Number of options		939,660	61,610	27,410	301,360
Options held at the end of the year					
Number of options		348,975	47,025	27,500	296,450
Options relevant to the year					
Fair value	(euro thousand)				

(1) Managers who, during the course of the year and with the Chief Executive Officer and Chief Operating Officers of Eni s Divisions, were permanent members of the Company Management Committee and the ones who report directly to the Chief Executive Officer (No. 12 managers).

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Board practices

Corporate Governance

The corporate governance structure of Eni SpA follows the Italian traditional management and control model, whereby corporate management is the responsibility of the Board of Directors, which is the core of the organizational system, while supervisory control functions are allocated to the Board of Statutory Auditors. The Company s accounts are also independently audited by an accredited Audit Firm appointed by the Shareholders Meeting. On April 26, 2012, Eni completed the adoption of the recommendations of the new Corporate Governance Code for listed companies (on the Italian Stock Exchange) of December 2011 (hereinafter "Corporate Governance Code"), which replaced the previous 2006 edition of the Corporate Governance Code.

The names of Eni s Directors, their positions, the year when each of them was initially appointed as a Director and their ages are reported in the related table above.

Board of Directors duties and responsibilities

The Board of Directors has the widest powers for the ordinary and extraordinary administration of the Company in relation to its purpose. In a resolution dated May 6, 2011, the Board, while exclusively reserving to itself the most important strategic, operational and organizational powers in addition to those that cannot be delegated by law, appointed Paolo Scaroni as CEO and General Manager, entrusting him with the widest powers for the ordinary and extraordinary administration of the Company. In the same resolution, the Board delegated to the Chairman, Giuseppe Recchi, powers to identify and promote integrated projects and international agreements of strategic importance, in accordance with Article 24 of the By-laws. On December 12, 2013, the Board amended the resolution of May 6, 2011. Exercising the powers set out in the Corporate Governance Code and in consultation with the relevant committees, the CEO, and/or the Chairman where applicable the Board, among other tasks:

- defines the system and rules of Corporate Governance for the Company and the Group;
- establishes the Board s internal committees, appoints their members and chairmen, determining their duties and compensation, and approves their rules of procedure and annual budgets;
- expresses the general criteria for determining the maximum number of offices that a Company Director may hold in other companies;
- delegates and revokes the powers of the CEO and the Chairman, establishing the limits and procedures for exercising those powers and determining the compensation associated with these duties;
- establishes the basic structure of the organizational, administrative and accounting arrangements of the Company (including the internal control and risk management system), of its strategically important subsidiaries and of the Group as a whole. It evaluates the adequacy of these arrangements;
- establishes the guidelines for the internal control and risk management system and sets the limits of the Company s financial risk exposure. It also examines the main risks faced by the Company, and evaluates, every six months, the adequacy of the internal control and risk management system, as well as the system s effectiveness;
- approves at least annually the audit plan drawn up by the Head of the Internal Audit Department. It also evaluates the findings contained in the recommendation letter, if any, of the external auditor and in its statement on the key issues that arose during the statutory audit;
- defines the strategic guidelines and objectives of the Company and the Group, including sustainability policies. It examines and approves the budgets and strategic, industrial and financial plans of the Group periodically monitoring their implementation, as well as agreements of a strategic nature for the Company;
- examines and approves the annual financial report including the individual and Consolidated Financial Statements and the semi-annual and quarterly financial reports required by applicable law. It reviews and approves the Sustainability Reporting not already contained in the financial report;

receives reports from Directors with delegated powers at Board meetings, or on at least a bi-monthly basis, on the actions taken in exercising their delegated powers;
receives a report from the Board s internal committees on at least a semi-annual basis;
assesses general developments in the operations of the Company and of the Group, paying particular attention to conflicts of interest and comparing the results with budget forecasts;
evaluates and approves transactions of the Company and its subsidiaries with related parties[16], as well as transactions in which the CEO has an interest;
evaluates and approves any transaction executed by the Company and its subsidiaries that has a significant strategic, economic, financial or asset impact for the Company;
appoints and removes the Chief Operating Officers, the Officer in charge of preparing financial reports, the Head of the Internal Audit Department and the Eni Watch Structure. It ensures the designation of a manager responsible for shareholders relations;
examines and approves the Remuneration Report and, in particular, the Remuneration Policy for Directors and Managers with strategic responsibilities to be presented to the Shareholders Meeting. It also defines the

(16) The Board of Directors, on November 18, 2010, approved the Management System Guideline (MSG) "Transactions involving interests of directors and statutory auditors and transactions with related parties", which has been applied since January 1, 2011, to ensure transparency and substantial and procedural fairness of transactions with related parties. The Board modified this MSG on January 19, 2012.

criteria for remunerating the senior executives of the Company and the Group and takes steps to implement compensation plans based on shares or other financial instruments approved by the Shareholders Meeting;
resolves on the exercise of voting rights and on the appointment of members of corporate bodies of the strategically important subsidiaries;
formulates the proposals to present to the Shareholders Meeting; and
examines and resolves on other issues that Directors with delegated powers believe should be presented to the Board due to their particular importance or sensitivity.

In accordance with Article 23.2 of the By-laws, the Board also resolves on mergers and proportional spin-offs of companies in which Eni s shareholding is at least 90%; the establishment and closing of branches; and the amendment of the By-laws to comply with the provisions of law.

In accordance with the By-laws, the Chairman and the Chief Executive Officer retain representative powers for the Company.

Directors independence

During its meeting of May 6, 2011 and, after an investigation by the Nomination Committee, at its meeting of February 14, 2012, the Board of Directors determined that the non-executive Directors Gatto, Lorenzi, Marchioni, Petri, Profumo, Resca and Taranto were independent.

These determinations were made by the Board on the basis of statements made by the Directors and other information available to the Company, and taking into account the criteria of independence established in Italian regulations and the Corporate Governance Code in force at that time. Director Resca was confirmed as being independent under the terms of the Corporate Governance Code in force at that time as well, even though he has held the position for over nine years in the last twelve years[17], in light of his recognized independence of judgment. With reference to the marital relationship of the Director Profumo with an employee of the Company, the Board believes that this relationship does not compromise the independence requirements requested by Corporate Governance Code in force at that time, in view of ethical and professional integrity of this Director and his international reputation. Director Gatto was confirmed as being independent even though he was appointed Chairman of the Board of the Statutory Auditors of Rai SpA, company under common control with Eni by the Ministry of the Economy and Finance, because of the independence required to the Board of Statutory Auditors and also for the particular discipline applicable to Rai SpA which limits the power of control of the Ministry of the Economy and Finance.

After the evaluation of the Board at the Meeting of February 14, 2012, in compliance with the independence requirements contained in the Corporate Governance Code (Article 3, c.4), which establishes that the Board of Directors shall assess the independence of a Director every time a material circumstance occurs, the Nomination Committee investigated, in its Meetings of September 20, 2012 and October 18, 2012, the independence of Director Profumo, who was appointed Chairman of the Board of Directors of Monte dei Paschi di Siena on April 27, 2012, taking into account the business relations between Eni and that Bank. The Nomination Committee acquired documentation concerning the financial relationships between Eni and Monte dei Paschi di Siena and the other information available to the Company, and confirmed[18] the independence of Director Profumo, determining that these business relations were not sufficient to undermine the independence requirements set out in the Corporate Governance Code. The Board of Directors, on the basis of the investigation of the Nomination Committee, confirmed, on October 29, 2012, that Director Profumo was independent.

At the meeting of February 14, 2013, the Board, upon prior investigation by the Nomination Committee, confirmed the previous evaluations on the independence of Directors according to the independence requirements contained in the Corporate Governance Code. In particular, the Board confirmed the independence requirements of Directors

Resca, Profumo and Gatto on the basis of the afore mentioned reasons. With reference to Director Gatto, who was subsequently appointed Chairman of the Board of Statutory Auditors of Rainet SpA (a subsidiary of Rai SpA), the Board confirmed his independence for the same reasons, mentioned above, regarding his role as Chairman of the Board of Statutory Auditors of Rai SpA.

The Board of Statutory Auditors has always monitored the correct application of the criteria and procedures adopted by the Board for assessing the independence of its members. Those independence criteria may not be equivalent to the independence criteria set forth by the NYSE listing standards applicable to a U.S. domestic company.

(17) Resca was appointed Director of the Board for the first time in 2002.
(18) The Director involved in the investigation performed by the Nomination Committee did not take part in the Meeting.

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Board Committees

The Board of Directors has established four internal committees to provide it with recommendations and advice: (a) the Control and Risk Committee[19]; (b) the Compensation Committee; (c) the Nomination Committee; and (d) the Oil-Gas Energy Committee. The Control and Risk Committee, the Compensation Committee and the Nomination Committee are recommended by the Corporate Governance Code. The composition, duties and operational procedures of these committees are governed by their rules, which are approved by the Board, in compliance with the criteria outlined in the Corporate Governance Code.

The committees provided for by the Corporate Governance Code (Control and Risk Committee, Nomination Committee and Compensation Committee) are composed of no fewer than three members and, in any case, less than a majority of members of the Board. The Control and Risk Committee, the Compensation Committee and the Oil-Gas Energy Committee are made up of non-executive, independent Directors. The Nomination Committee is made up of non-executive Directors, a majority of whom are independent in compliance with the Corporate Governance Code. In the exercise of their functions, the committees have the right to access any information and Company functions necessary to perform their duties. They are also provided with adequate financial resources, in accordance with the terms established by the Board of Directors, and can avail themselves of external advisers.

The Chairman of the Board of Statutory Auditors or a Statutory Auditor designated by him, may participate in Control and Risk Committee meetings. The Chairman of the Board, the CEO, the other standing Statutory Auditors and the Magistrate of the Italian Court of Auditors may also attend the Control and Risk Committee meetings. Furthermore, the Committee may, through its Chairman, invite other persons, including other member of the Board of Directors or the Company structure, to attend the meetings in relation to individual items on the agenda.

The Chairman of the Board of Statutory Auditors, or a standing Statutory Auditor designated by him, are invited to participate in Compensation Committee meetings. Other Statutory Auditors may also attend meetings in which the Committee is addressing issues about which the Board of Directors is required to obtain an opinion from the Board of Statutory Auditors. Company managers or other persons who, at the invitation of the Chairman of the Committee, are called to provide information and or opinions based on their expertise on specific items on the agenda may also attend the meetings. No Director may take part in meetings of the Committee during which Board proposals regarding his compensation are being discussed.

The Chairman of the Board of Directors and the CEO are invited to attend Oil-Gas Energy Committee meetings and other Directors may also participate. The Chairman of the Board of Statutory Auditors or another standing Statutory Auditor designated by the former may also participate as well as other individuals, who need not be affiliated with Eni, at the invitation of the Committee with regard to the specific items in the agenda.

The CEO attends the Nomination Committee meetings. The Chairman of the Board of Statutory Auditors, or a Statutory Auditor designated by him, may participate in Committee meetings for matters within the competence of the Board of Statutory Auditors, as well as other persons who, at the invitation of the Committee itself, are called to provide information and or opinions based on their expertise on specific items in the agenda.

Minutes of all committee meetings are drafted by the respective secretaries. The current members of the Control and Risk Committee, Compensation Committee, Oil-Gas Energy Committee were appointed by the Board of Directors on May 6, 2011. The current members of the Nomination Committee were appointed by the Board of Directors on July 28, 2011.

Compensation Committee
Members: Mario Resca (Chairman), Carlo Cesare Gatto, Roberto Petri and Alessandro Profumo.

Established by the Board of Directors for the first time in 1996, in accordance with the By-laws, the Committee provides recommendations and advice to the Board of Directors. More specifically, the Committee: a) submits to the Board of Directors for its approval the Remuneration Report and, in particular, the remuneration policy for Directors and Managers with strategic responsibilities to be presented to the Shareholders Meeting called to approve the financial statements, as provided for by applicable law; b) presents proposals for the remuneration of the Chairman of the Board and the Chief Executive Officer, covering the various forms of compensation and benefits awarded; c) presents proposals for the remuneration of members of the Board s internal committees; d) examines the CEO s indications and presents proposals for: (i) general criteria for compensation of the Managers with strategic responsibilities; (ii) annual and long-term incentive plans, including equity-based plans; and (iii) establishing performance targets and assessing results for performance plans in connection with the determination of the variable portion of the compensation for Directors with delegated powers and with the implementation of incentive plans; e) monitors the execution of Board resolutions regarding remuneration matters; f) periodically evaluates the adequacy, overall consistency and actual

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(19) The Internal Control Committee, created within the Board of Directors for the first time on February 9, 1994, changed its name to the "Control and Risk Committee" with a Resolution dated July 31, 2012.

implementation of the adopted policy, as described in letter a) above, formulating proposals on the topic for the Board of Directors; g) performs the tasks required under the Company s procedures for handling related party transactions; h) reports to the Board, at least once every six months and no later than the deadline for the approval of the annual financial statements and the semi-annual financial report, on its activities at the Board Meeting indicated by the Chairman of the Board of Directors; and i) reports through its Chairman or another Committee member designated by the Chairman on its operational procedures to the Shareholders Meeting called to approve the financial statements. The Committee is provided with the resources required to perform its duties, within the budget established by the Board, and can avail itself, within those limits and acting through Company structures, of external advisors who are not in positions that might compromise their independence of judgment. The Committee may access the information and Company functions necessary to perform its duties.

During 2013, the Compensation Committee met seven times, with an attendance rate of about 93% of its members and the main topics discussed in the first part of the year were: (i) periodical evaluation of the remuneration policy carried out in 2012, even for the definition of the proposal guidelines of remuneration policy 2013; (ii) evaluation of the attainment of Eni s 2012 management objectives and definition of 2013 performance objectives for the purposes of variable Incentive Plans; (iii) establishment of the proposals regarding the Deferred Monetary Incentive Plan for the CEO and General Manager and for other executives; and (iv) examination of the 2013 Remuneration Report. During the second part of the year, the Committee examined the results of the vote of the Shareholder s Meeting on the Remuneration Policy for 2013 and the planned guidelines for the preparation of the 2014 Remuneration Report. The Committee also formulated the proposal concerning the fulfillment of the Long-Term Monetary Incentive Plan for the CEO and General Manager and for critical management personnel. Furthermore, for the proposal to be presented to the Shareholder s Meeting for approval, the Committee evaluated the effects for Eni of the new Italian Law No. 98/2013, regarding the reduction of remuneration for Directors with delegated power in listed companies controlled by government entities.

The composition and appointment, as well as duties and operational rules, of the Committee are governed by rules approved by the Board of Directors on June 1, 2011, and amended on December 15, 2011 and on October 29, 2012, available to the public at the Company s website.

Control and Risk Committee
Members: Alessandro Lorenzi (Chairman), Carlo Cesare Gatto, Paolo Marchioni and Francesco Taranto.

The Control and Risk Committee is entrusted with supporting, on the basis of an appropriate control process, the Board of Directors in evaluating and making decisions concerning the internal control and risk management system and in approving the periodic financial reports. It is entirely made up of non-executive and independent Directors[20] who possess the necessary expertise consistent with the duties they are required to perform[21].

The Committee advises the Board of Directors and specifically issues its prior opinion: a) and drafts recommendations concerning the guidelines for the internal control and risk management system so that the main risks faced by the Company and its subsidiaries can be correctly identified and appropriately measured, managed and monitored, and determines the degree of compatibility of such risks with the management of the Company in a manner consistent with its stated strategic objectives; b) on the evaluation, performed at least once a year, of the adequacy of the internal control and risk management system, taking account of the characteristics of the Company and its risk profile, as well as its effectiveness. To this end, at least once every six months it reports to the Board of Directors, on the occasion of the approval of the annual and semi-annual financial reports, on its activities and on the adequacy of the internal control and risk management system at the Meeting of the Board of Directors indicated by the Chairman of the Board of Directors; c) on the approval, at least once a year, of the Audit Plan prepared by the Senior Executive Vice

President of the Internal Audit Department; d) on the description, in the annual Corporate Governance Report, of the main features of the internal control and risk management system, providing its evaluation of the overall adequacy of the system itself; e) on the evaluation of the findings reported by the Audit Firm in the recommendations letter it may issue and in the latter s report on the main issues arising during the audit; f) on specific aspects concerning the identification of the main risks faced by the Company, as well as on the design, implementation and management of the internal control and risk management system; and g) on the adoption and amendment of the rules on the transparency and the substantive and procedural fairness of transactions with related parties and those in which a Director or Statutory Auditor holds a personal interest or an interest on behalf of a third party, while performing the additional duties assigned it by the Board of Directors, including examining and issuing an evaluation on specific types of transactions, except for those relating to compensation.

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(20) In accordance with the rules of the Control and Risk Committee, the Committee is made up of three to four non-executive Directors, all of whom are independent. Alternatively, the Committee may be made up of non-executive Directors a majority of whom shall be independent. In the latter case, the Chairman of the Committee shall be chosen from among the independent Directors. In any case, the number of members shall be fewer than the number representing a majority on the Board.

(21) The governance system put in place by Eni establishes that at least two members of the Committee and not just one as recommend by the Corporate Governance Code for listed companies must possess adequate experience on financial and accounting matters, as assessed by the Board of Directors at the time of their appointment.

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In addition, the Committee, in assisting the Board of Directors: (i) evaluates, together with the officer in charge of preparing financial reports and after having consulted the Audit Firm and the Board of Statutory Auditors, the proper application of accounting standards and their consistency in preparing the Consolidated Financial Statements, prior to their approval by the Board of Directors; (ii) examines and evaluates the appropriateness of the powers and resources assigned to the officer in charge of preparing financial reports and, also for the purposes of overseeing the proper application of accounting standards and their consistency, performs the duties assigned it under the MSG on "Eni s internal control system over financial reporting", including examining the report on the internal control system for financial reporting prepared by the officer in charge of preparing financial reports at the time of the approval of the consolidated annual and semi-annual financial statements; and (iii) monitors the independence, adequacy, efficiency and effectiveness of the Internal Audit Department and oversees its activities with respect to the Board of Directors duties in this area, ensuring that they are performed with the necessary independence and required level of objectivity, competence and professional diligence, in accordance with the Code of Ethics of Eni SpA and international standards. Among its other duties, the Committee examines: a) the periodic report prepared by the Senior Executive Vice President of the Internal Audit Department containing adequate information on the activities carried out, on the manner in which risk management is conducted and on compliance with risk containment plans, as well as the assessment of the appropriateness of the internal control and risk management system; b) the reports prepared promptly by the Senior Executive Vice President of the Internal Audit Department on events of particular importance; and c) the information received from the Senior Executive Vice President of the Internal Audit Department and promptly reports its assessment to the Board of Directors in the case of significant deficiencies in the system for preventing irregularities and fraudulent acts, and irregularities or fraudulent acts committed by management personnel or by employees that perform important roles in the design or operation of the internal control and risk management system.

The Committee may also ask the Internal Audit Department to perform audits of specific operational areas, providing simultaneous notice to the Chairman of the Board of Statutory Auditors. The Committee also examines and assesses: (i) communications and information received from the Board of Statutory Auditors and its members regarding the internal control and risk management system, including those concerning the findings of enquiries conducted by the Internal Audit Department in connection with reports received (whistleblowing), including anonymous reports; (ii) periodic reports issued by Eni s Watch Structure, including in its capacity as Guarantor of the Code of Ethics; (iii) information on the internal control and risk management system, including that provided in the course of periodic meetings with the competent Company structures; and (iv) enquiries and reviews concerning the internal control and risk management system carried out by third parties.

The composition and appointment, as well as duties and operational procedures of the Committee, are governed by rules approved by the Board of Directors on June 1, 2011 and amended on July 31, 2012, available to the public at the Company s website.

Nomination Committee
Members: Giuseppe Recchi (Chairman), Alessandro Lorenzi, Alessandro Profumo and Mario Resca.

On July 28, 2011, the Board of Directors of Eni established the Nomination Committee, chaired by the Chairman of the Board of Directors. The Committee is made up of three to four Directors, a majority of whom are independent.

The Committee provides the Board of Directors with recommendations and advice. In particular, the Committee: (a) assists the Board of Directors in formulating the criteria for the appointment of persons indicated in following letter and of members of the other boards and bodies of Eni s subsidiaries and associated companies; (b) provides evaluations to the Board of Directors on the appointment of executives and members of the boards and bodies of the

Company and of its subsidiaries, proposed by the Chief Executive Officer, whose appointment fall under the Boards responsibility and oversees the associated succession plans. Where possible and appropriate, in relation with the shareholders structure, the Committee proposes to the Board of Directors the succession plan concerning the Chief Executive Officer; (c) acting upon proposal of the Chief Executive Officer, examines and evaluates criteria governing the succession plan for the Company s key management personnel; (d) proposes candidates to serve as Directors on the Board of Directors in the event one or more positions need to be filled during the course of the financial year (Article 2386, first paragraph, of the Italian Civil Code), ensuring compliance with the requirements on the minimum number of independent Directors and of the percentage reserved for the less represented gender; (e) proposes to the Board of Directors candidates for the position of Director to be submitted to the Shareholders Meeting of the Company, taking account of any recommendation received from shareholders, in the event it is not possible to draw the required number of Directors from the slates presented by shareholders; (f) oversees the annual self-assessment program on the performance of the Board of Directors and its Committees, in compliance with the Corporate Governance Code, and on the basis of the results of the self-assessment, provides its opinions to the Board of Directors regarding the size and composition of the Board or its Committees, as well as the skills and professional qualifications it feels should be represented on the same, so that the Board itself can give its opinion to the shareholders prior to the appointment of the new Board; (g) proposes to the Board of Directors the slate of candidates for the position of Director, to be submitted to the Shareholders Meeting if the Board decides to opt for the process envisaged in Article 17.3 of the By-laws; (h) in compliance with the Corporate Governance Code, proposes to the Board of Directors guidelines regarding the maximum number of positions of Director or statutory auditor that a Company Director may hold and performs the associated periodic checks and evaluations to be submitted to the Board; (i) periodically verifies that the Directors satisfy the independence and integrity requirements and ascertains the absence of circumstances that would render them incompatible or ineligible; (j) provides its opinion to the Board of Directors on any activities carried out by the Directors in competition with the Company; and (k) reports to the Board of Directors, at least once every six months and not later than the deadline for the approval of the annual financial statements and of the semi-annual Financial Report, on the activity carried out, as well as on the adequacy of the appointment system, at the Board Meeting indicated by the Chairman of the Board of Directors.

The composition, appointment, duties and operational procedures of the Nomination Committee are governed by rules approved by the Board of Directors on September 29, 2011 and amended on October 29, 2012, available to the public at the Company s website.

Board of Statutory Auditors

The current Board of Statutory Auditors was appointed by the Ordinary Shareholders Meeting of May 5, 2011 for a term of three financial years. The Board s term will therefore expire with the Shareholders Meeting called to approve the financial statements for the year ending December 31, 2013. On September 5, 2013, in accordance with the Italian specific regulations of 2012, Roberto Ferranti resigned from Eni s Board of Statutory Auditors due to the incompatibility with the position taken in the Board of Directors of Cassa Depositi e Prestiti SpA and has been replaced by Francesco Bilotti, Alternate Auditor drawn from the list of candidates presented by the Shareholder Ministry of the Economy and Finance.

Name	**Position**	**Year first appointed to Board of Statutory Auditors**
Ugo Marinelli	Chairman	2008
Roberto Ferranti (*)	Auditor	2008
Francesco Bilotti (**)	Auditor	2013
Paolo Fumagalli	Auditor	2011
Renato Righetti	Auditor	2011
Giorgio Silva	Auditor	2005
Maurizio Lauri	Alternate Auditor	2011

(*) Auditor until September 5, 2013.
(**) As of September 5, 2013. Alternate Auditor since 2005.

Roberto Ferranti, Paolo Fumagalli, Renato Righetti and Francesco Bilotti were candidates in the list presented by the Ministry of the Economy and Finance; Ugo Marinelli, Giorgio Silva and Maurizio Lauri were candidates in the list presented by non-controlling shareholders (institutional investors).

The Auditors are appointed by means of a slate voting system: the lists are presented by shareholders representing at least 0.5% of the share capital. Two standing Statutory Auditors and one Alternate Auditor are selected from among the candidates of the non-controlling shareholders. The Chairman of the Board of Statutory Auditors is appointed by the Shareholders Meeting from among the Auditors elected by the non-controlling shareholders.

The Auditors must satisfy the independence, professional and integrity requirements established by Italian regulations. Article 28 of the By-laws specifies that the professionalism requirements may be fulfilled by having at least three years in: (i) professional or teaching activities pertaining to commercial law, business economics and corporate finance, or (ii) experience in executive positions in the fields of engineering and geology. U.S. Regulations for Audit Committees require that at least one member of the Board of Statutory Auditors shall be a financial expert and have adequate knowledge of the functions of the Audit Committee and experience in the analysis and application of generally accepted accounting standards, preparation and auditing of financial statements and internal control processes.

Pursuant to the Consolidated Law on Financial Intermediation, the Board of Statutory Auditors monitors: (i) compliance with the law and the Company s By-laws; (ii) observance of the principles of sound administration; (iii) the appropriateness of the Company s organizational structure for matters within the scope of the Board s Authority, the adequacy of the internal control system and the administrative and accounting system and the reliability of the latter in accurately representing the Company s transactions; (iv) the procedures for implementing the corporate governance rules provided for in the Corporate Governance Code, which the Company has adopted; and (v) the adequacy of the instructions imparted by the Company to its subsidiaries, in order to guarantee full compliance with legal reporting requirements.

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In addition, pursuant to Article 19 of Legislative Decree No. 39/2010, in its role as the "internal control and financial auditing committee" the Board of Statutory Auditors oversees the following: a) the financial reporting process; b) the efficacy of internal control, internal audit (where applicable) and risk management systems; c) the auditing of the annual financial statements and consolidated financial statements; and d) the independence of the external auditor or the Audit Firm, in particular with regard to the provision of non-audit services to the entity subject to financial auditing.

The responsibilities assigned under the Legislative Decree No. 39/2010 to the "internal control and financial auditing committee" are consistent and substantively in line with the duties already assigned to the Board of Statutory Auditors of Eni, with specific consideration of its role as Audit Committee pursuant to the "U.S. Sarbanes-Oxley Act" (discussed in greater detail below).

As already set forth in the Consolidated Law on Financial Intermediation and currently regulated by Article 13 of Legislative Decree No. 39/2010, the Board of Statutory Auditors submits a reasoned opinion to the Shareholders Meeting on the selection of the external auditors and the determination of the associated fees.

Furthermore, pursuant to Article 19, paragraph 1, letters c) and d) of Legislative Decree No. 39/2010, the Board of Statutory Auditors supervises the auditing activities and the independence of the Audit Firm, verifying compliance with all applicable regulations, as well as the nature and scale of any services other than financial auditing services provided to the Eni Group, either directly or through companies belonging to its network. In accordance with Article 153 of the Consolidated Law on Finance, the Board of Statutory Auditors presents the results of its supervisory activity in a report. This report is made available in its entirety to the public within the time limits applicable to the financial statements. On March 22, 2005, the Board of Directors, electing the exemption granted by the U.S. Securities and Exchange Commission applicable to foreign issuers listed on the regulated U.S. markets, designated the Board of Statutory Auditors as the body that, as of June 1, 2005, would perform, to the extent permitted under Italian regulations, the functions attributed to the Audit Committee of foreign issuers by the Sarbanes-Oxley Act and U.S. SEC rules. On June 15, 2005, the Board of Statutory Auditors approved the internal rules concerning its performance of the duties assigned to it under that U.S. legislation, the text of which is available on Eni s website. The key functions performed by the Board of Statutory Auditors acting as an audit committee as provided for by U.S. SEC rules are as follows:

- evaluating the offers submitted by external auditors for their engagement and providing a reasoned recommendation to the Shareholders Meeting concerning the engagement or removal of the external auditor;
- overseeing the work of the external auditor engaged to audit the account or performing other audit, review or certification services;
- making recommendations to the Board of Directors on the resolution of disagreements between management and the auditor regarding financial reporting;
- approving the procedures for: a) the receipt, retention, and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters; and b) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters;
- approving the procedures for the pre-approval of specifically identified admissible non-audit services and examining the disclosures on the execution of the authorized services;
- evaluating requests to use the external auditor firm engaged to perform audit services for admissible non-audit services and providing its opinion to the Board of Directors;
- examining the periodical reports from the external auditor relating to: a) all critical accounting policies and practices to be used; b) all alternative treatments of financial information within generally accepted accounting principles that have been discussed with management officials of the Company, ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditor; and c) other material written communication between the external auditor and management;

- examining reports from the CEO and the CFO concerning any significant deficiency in the design or operation of internal controls which are reasonably likely to adversely affect the Company s ability to record, process, summarize and report financial information and any material weakness in internal controls; and
- examining reports from the CEO and the CFO concerning any fraud that involves management or other employees who have a significant role in the Company s internal controls.

The Board of Statutory Auditors, in the execution of its functions, is supported by Company s departments, in particular the Internal Audit Department and the Administrative and Financial Statement Department.

Eni Watch Structure and Model 231

In accordance with the Italian regulations concerning the "administrative liability of legal entities deriving from criminal offences", contained in Legislative Decree No. 231 of June 8, 2001 (henceforth, "Legislative Decree No. 231/2001"), legal entities, including corporations, may be held liable and consequently fined or subject to prohibitions in relation to certain crimes attempted or committed in Italy or abroad in the interest or for the benefit of the Company by individuals in high-ranking positions and/or persons managed or supervised by an individual in an high-ranking position. The companies may, in any case, adopt organizational, management and control models designed to prevent these crimes. With respect to this issue, Eni SpA s Board of Directors in its meetings of December 15, 2003 and January 28, 2004 approved an organizational, management and control model pursuant to Legislative

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Decree No. 231 of 2001 (Model 231) and created the Watch Structure. Moreover, as a result of changes in the Italian legislation governing the matter and of the Company s organizational structures, on March 14, 2008, the Board of Director updated Model 231 and adopted Eni s Code of Ethics replacing the previous version of the Eni Code of Conduct of 1998 which represents a clear definition of the value system that Eni recognizes, accepts and upholds and the responsibilities that Eni assumes internally and externally in order to ensure that all business activities are conducted in compliance with laws, in a context of fair competition, with honesty, integrity, correctness and in good faith, respecting the legitimate interests of all stakeholders with which Eni relates on an ongoing basis. These include shareholders, employees, suppliers, customers, commercial and financial partners, and the local communities and institutions of the countries where Eni operates. The synergies between the Code of Ethics an integral part and essential general principle of Model 231 and Model 231 are highlighted by the assignment, to the Eni Watch Structure, of the function of Guarantor of the Code of Ethics. In the second half of the 2013, following updates to the special section of the Model 231 report (Sensitive activities and specific control standards) in compliance with the new anti-bribery regulations, Eni's Watch Structure agreed on the advisability of starting the project for updating the General Part of the Model 231. The composition of the Eni Watch Structure, initially composed of only three members, was modified in 2007 with the inclusion of two external members, one of whom was appointed as Chairman of the Eni Watch Structure selected among academics and professionals of proven authority and expertise in economic and business management issues. The internal members are the Senior Executive Vice President Legal Affairs, Executive Vice President Human Resources and Organization and Senior Executive Vice President Internal Audit of the Company. On May 19, 2011, the Board of Directors, with the favorable opinion of the Board of Statutory Auditors, appointed the current members of the Watch Structure.

Audit Firm

The auditing of the Company s accounts is entrusted, in accordance with the law, to an independent Audit Firm appointed by the Shareholders Meeting on the basis of a reasoned recommendation of the Board of Statutory Auditors.

In addition to the obligations set forth in national auditing regulations, Eni s listing on the New York Stock Exchange requires that the Audit Firm issue a report on the Annual Report on Form 20-F, in compliance with the auditing principles generally accepted in the United States. Moreover, the Audit Firm is required to issue an opinion on the efficacy of the internal control system applied to financial reporting.

For the most part, the subsidiaries financial statements are subject to auditing by Eni s Audit Firm. Moreover, Eni s Audit Firm, for the purpose of issuing an opinion on the Consolidated Financial Statements, assumes responsibility for the auditing activities performed by other audit firms with respect to subsidiaries financial statements, which, taken together, account for an immaterial share of consolidated assets and revenues.

Acting on the Board of Statutory Auditors reasoned proposal, the Shareholders Meeting of April 29, 2010 appointed Reconta Ernst & Young SpA for the financial years 2010-2018.

Court of Auditors (Corte dei conti)

The financial management of Eni is subject to the control of the Court of Auditors in order to preserve the integrity of the public finances. This work is performed by the Magistrate of the Court of Auditors, Raffaele Squitieri, on the basis of the resolution approved on October 28, 2009 by the Presidential Council of the Court of Auditors. The Magistrate of the Court attends the meetings of the Board of Directors, of the Board of Statutory Auditors and of the Control and Risk Committee.

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Employees

As of December 31, 2013, Eni had a total of 83,887 employees, an increase of 4,482 employees, or up 5.6% from December 31, 2012, which reflects an increase of 4,501 employees working outside Italy and a decrease of 19 employees hired in Italy.

	2011	2012 (1)	2013
		(units)	
Exploration & Production	10,425	11,304	12,352
Gas & Power (2)	4,795	4,836	4,616
Refining & Marketing	7,591	8,608	8,438
Chemicals	5,804	5,668	5,708
Engineering & Construction	38,561	43,387	47,209
Other activities	880	871	818
Corporate and financial companies	4,518	4,731	4,746
	72,574	**79,405**	**83,887**

(1) The numbers for 2012 have been restated following the adoption of IFRS 11.
(2) Following the deconsolidation of Snam in 2012, employees of the Gas & Power business segment include Marketing and International transport activities. Prior year data have been restated.

The table below sets forth Eni s employees as of December 31, 2011, 2012 and 2013 in Italy and outside Italy:

		2011	2012 (1)	2013
			(units)	
Exploration & Production	Italy	3,797	3,933	4,133
	Outside Italy	6,628	7,371	8,219
		10,425	11,304	12,352
Gas & Power (1)	Italy	2,310	2,126	2,178
	Outside Italy	2,485	2,710	2,438
		4,795	4,836	4,616
Refining & Marketing	Italy	5,790	6,098	5,909
	Outside Italy	1,801	2,510	2,529
		7,591	8,608	8,438
Chemicals	Italy	4,750	4,606	4,615
	Outside Italy	1,054	1,062	1,093
		5,804	5,668	5,708
Engineering & Construction	Italy	5,197	5,186	5,136
	Outside Italy	33,364	38,201	42,073
		38,561	43,387	47,209
Other activities	Italy	880	871	818
	Outside Italy	-	-	-
		880	871	818
Corporate and financial companies	Italy	4,334	4,577	4,589
	Outside Italy	184	154	157
		4,518	4,731	4,746
Total	Italy	27,058	27,397	27,378
	Outside Italy	45,516	52,008	56,509
		72,574	**79,405**	**83,887**
of which senior managers		1,468	1,504	1,505

(1) The numbers for 2012 have been restated following the adoption of IFRS 11.
(2) Following the deconsolidation of Snam in 2012, employees of the Gas & Power business segment include Marketing and International transport activities. Prior year data have been restated.

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Share Ownership

As of February 28, 2014, the cumulative number of shares owned by Eni s directors, statutory auditors and senior managers, including the two Chief Operating Officers, was 299,772 less than 0.1% of Eni s share capital outstanding as of the same data. Eni issues only ordinary shares, each bearing one-vote right; therefore shares held by those persons have no different voting rights. The breakdown of share ownership for each of those persons is provided below.

Name	Position	Number of shares owned	Options granted
Board of Directors			
Giuseppe Recchi	Chairman	46,300	
Paolo Scaroni	CEO and COO of Eni	91,250	348,975
Carlo Cesare Gatto	Director	6,800	
Paolo Marchioni	Director	1,500	
Alessandro Profumo	Director		4,675
Mario Resca	Director	3,900	
Francesco Taranto	Director	500	
Chief Executive Officers			
Claudio Descalzi	Chief Operating Officer of the E&P Division	39,455	47,025
Angelo Fanelli	Chief Operating Officer of the R&M Division	30,800	27,500
Board of Statutory Auditors		**7,454**	
Senior managers		**71,813**	**296,450**

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Item 7. MAJOR SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

Major Shareholders

The Ministry of Economy and Finance controls Eni as a result of shares held directly and indirectly through Cassa Depositi e Prestiti SpA (CDP), in which the Ministry of Economy and Finance holds a 80.10% stake.

As of March 28, 2014, the total amount of Eni SpA s voting securities owned by these shareholders was:

Title of class	Number of shares owned	Percent of class
Ministry of Economy and Finance	157,552,137	4.34
Cassa Depositi e Prestiti SpA	936,179,478	25.76

The following table shows the percentage of Eni s share capital owned directly or indirectly by subjects that as of March 28, 2014, have notified that their holding exceeds the threshold of 2% pursuant to Article 120 of Italian Consolidated Law on Financial Intermediation and to Consob Resolution No. 11971/99 (Consob Regulations on Issuers).

Title of class	Percent of class
People s Bank of China	2.102

The Ministry of Economy and Finance, in agreement with the Ministry of Economic Development, pursuant to Article 6.2 of the By-laws and to the special rules set out in Law No. 474/1994, retains certain special powers over Eni. See "Item 10 Additional information Limitations on changes in control of the Company (Special Powers of the Italian State)". As of March 28, 2014, there were 33,707,883 ADRs outstanding, each representing two Eni ordinary shares, corresponding to approximately 1.9% of Eni s share capital. See "Item 9 The offer and the listing".

Related party transactions

In the ordinary course of its business, Eni enters into transactions concerning the exchange of goods, provision of services and financing with non-consolidated subsidiaries and affiliates as well as other companies owned or controlled by the Italian Government. All such transactions are conducted on an arm s length basis and in the interest of Eni companies.

Amounts and types of trade and financial transactions with related parties and their impact on consolidated earnings and cash flow, and on the Group s assets and financial condition are reported in "Item 18 note 43 of the Notes to the Consolidated Financial Statements".

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Item 8. FINANCIAL INFORMATION

Consolidated Statements and other financial information

See "Item 18 Financial Statements".

Legal proceedings

Eni is a party to a number of civil actions and administrative arbitral and other judicial proceedings arising in the ordinary course of business. Based on information available to date, and taking into account the existing risk provisions, Eni believes that the foregoing will not have an adverse effect on Eni s Consolidated Financial Statements.

For a description of legal proceedings in which Eni is involved and which may affect Eni s financial position and results of operations see "Item 18 note 34 of the Notes to the Consolidated Financial Statements".

Saipem proceedings with the Consob and the restatement of its 2012 financial statements

On July 19, 2013, Consob communicated to Saipem the commencement of a proceeding to review potential issues of non-compliance in Saipem s 2012 Separate and Consolidated Financial Statements with the accounting standard IAS 11 (Construction contracts). In its 2013 Annual Report, in accordance with IAS 8, paragraph 42, Saipem restated the 2012 comparative financial data to recognize a euro 245 million reduction of net profit due to a corresponding reduction of revenue relating to certain contracts that were in progress at December 31, 2012, the accounting of which as initially made by Saipem in 2013 was questioned by Consob; as a result, Consob informed Saipem of its decision to conclude the proceeding.

Eni s Consolidated Financial Statements for the years ending December 31, 2013 and 2012 do not reflect the restatement made by Saipem since the error is not material to Eni s Consolidated Financial Statements; therefore, the Eni s 2013 consolidated results include the euro 245 million reduction of revenue and net profit, which were recognized by Saipem in the 2012 restated comparative financial data.

Dividends

Eni s future dividend policy, as well as the sustainability of the current amount of dividends to be distributed over the next four years, will depend upon a number of factors including future levels of profitability and cash flow provided by operating activities, a sound balance sheet structure, capital expenditures and development plans, in light of the "Risk factors" set out in Item 3. The parent company s net profit and, therefore, the amounts of earnings available for the payment of dividends will also depend on the level of dividends received from Eni s subsidiaries. However, given the Company s changed business profile which entails both more growth options and more volatile results, as well as and improved balance sheet, management plans to implement a progressive dividend policy which contemplates an increasing dividend at a rate which is expected to be set taking into account Eni s underlying earnings and cash flow growth as well as capital expenditure requirements and the targeted financial structure. Management will also evaluate the achievement of the targeted production levels in the Exploration & Production segment, the status of renegotiations at gas long-term supply contracts in the Gas & Power segment and the delivery on efficiency gains in the downstream businesses. This dividend policy is based on management s planning assumptions for oil prices at 104 $/BBL in 2014 which will gradually decline to our long-term case of 90 $/BBL in 2017 period.

At the Annual Shareholders Meeting scheduled on May 8, 2014, management intend to propose the distribution of a dividend of euro 1.10 per share for fiscal year 2013, of which euro 0.55 was already paid as interim dividend in September 2013. Total cash outlay for the 2013 dividend is expected at approximately euro 3.95 billion (including euro 1.99 billion already paid in September 2013) if the Annual Shareholders Meeting approves the annual dividend. In future years, management expects to continue paying interim dividends for each fiscal year, with the balance to the full-year dividend to be paid in each following year. For further information about the Company s dividend policy see "Item 5 Management s expectations of operations".

Significant changes

See "Item 5   Recent developments" for a discussion of significant events occurred after 2013 year end up to the latest practicable date.

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Item 9. THE OFFER AND THE LISTING

Offer and listing details

The principal trading market for the ordinary shares of Eni SpA (Eni), without indication of par value (the "Shares"), is the Mercato Telematico Azionario (Electronic Share Market or "MTA"). MTA, which is the principal trading market for shares in Italy, is a regulated market organized and managed by Borsa Italiana SpA (Borsa Italiana). Eni s American Depositary Receipts (ADRs), each representing two Shares, are listed on the New York Stock Exchange.

The table below sets forth the reported high and low reference prices of Shares on MTA and of ADRs on the New York Stock Exchange, respectively. See "Item 3 Key information Exchange rates" regarding applicable exchange rates during the periods indicated below.

	MTA		New York Stock Exchange	
	High	Low	High	Low
	(euro per share)		(US$ per ADR)	
Year ended December 31,				
2009	18.350	12.300	54.450	31.070
2010	18.560	14.610	53.890	35.370
2011	18.420	12.170	53.740	32.980
2012	18.700	15.250	49.440	36.850
2013	19.480	15.290	52.120	40.390
2012				
First quarter	18.670	16.200	49.440	41.420
Second quarter	17.570	15.340	46.960	37.920
Third quarter	18.700	15.250	48.970	36.850
Fourth quarter	18.540	17.020	49.220	43.890
2013				
First quarter	19.480	17.010	52.120	44.360
Second quarter	18.980	15.290	48.960	40.390
Third quarter	17.950	15.710	48.500	40.660
Fourth quarter	18.650	16.300	50.800	44.920
2014				
First quarter (to March 28, 2014)	18.180	16.250	50.000	43.790
Month of				
October 2013	18.650	17.100	50.800	45.400
November 2013	18.490	17.710	50.800	43.790
December 2013	17.570	16.300	48.580	44.920
January 2014	17.660	16.730	48.300	45.400
February 2014	17.480	16.250	48.040	43.790
March 2014 (through March 28, 2014)	18.180	17.120	50.000	47.000

Until January 17, 2012, JPMorgan Chase Bank NA functioned as depositary banking issuing ADRs pursuant to a deposit agreement among Eni, the depositary bank and the beneficial owners and registered holders from time to time of the ADRs issued hereunder.

Effective January 18, 2012, the Bank of New York Mellon (the "Depositary") functions as depositary bank issuing ADRs pursuant to a deposit agreement (the "Deposit Agreement") among Eni, the Depositary and the beneficial owners ("Beneficial Owners") and registered holders from time to time of the ADRs issued hereunder.

As of March 28, 2014, there were 33,707,883 ADRs outstanding, representing 67,415,766 ordinary shares or approximately 2% of all Eni s shares outstanding, held by 115 holders of record (including the Depository Trust Company) in the United States, 113 of which are U.S. residents. Since certain of such ADRs are held by nominees, the number of holders may not be representative of the number of Beneficial Owners in the United States or elsewhere.

The Shares are included in the FTSE MIB Index (the "FTSE MIB"), the primary benchmark index for the Italian stock market. Capturing approximately 80% of the domestic market capitalization, the FTSE MIB measures the performance of 40 highly liquid, leading companies across leading industries listed on MTA and the Investment Vehicles Market (MIV) and seeks to replicate the broad sector weights of the Italian stock market. The constituents of the FTSE MIB are selected based on market capitalization of free-float shares and liquidity. The FTSE MIB is market cap-weighted after adjusting constituents for float. Since June 1, 2009, the FTSE MIB (previously S&P/MIB Index) is the principal indicator used to track the performance of the Italian stock market and is the basis for future and option contracts traded on the Italian Derivatives Market (IDEM) managed by Borsa Italiana. The Shares are the first largest component of the FTSE MIB, with a weighting of approximately 15%, as established by FTSE after the quarterly rebalancing for FTSE MIB effective March 24, 2014.

Trading in the MTA is allowed in any quantity of the Shares, as well as other financial instruments. Where necessary, Borsa Italiana may specify a minimum lot for each financial instrument. Since March 28, 2000, a three-day rolling cash settlement has been applied to all trades of equity securities in Italy. On February 6, 2014, Borsa Italiana announced that beginning from October 6, 2014, a two-day rolling cash settlement will be applied to all trades of equity securities in Italy. In addition, futures and options contracts on the Shares are traded on IDEM and securitized derivatives based on the Shares are traded on the Italian Securitized Derivatives Market (SeDeX). IDEM facilitates the trading of futures and options contracts on index and shares issued by companies that meet certain required capitalization and liquidity thresholds. SeDeX is the Borsa Italiana electronic regulated market where it is possible to trade securitized derivatives (for instance, covered warrants and certificates).

Borsa Italiana disseminates daily market data and news for each listed security, including volume traded and high and low prices. At the end of each trading day an "official price", calculated as the weighted average price of the total volume of each security traded in the market during the session without taking into account the contracts concluded with cross trades and block trades, and a "reference price", calculated as the closing auction price, are reported by Borsa Italiana. For the purposes of the automatic control of the regularity of trading on MTA, the following price variation limits shall apply to contracts concluded on shares making up the FTSE MIB, effective July 1, 2013: (i) ± 5.0% (or such other amount established by Borsa Italiana in the "Guide to the Parameters" for trading on the regulated markets organized and managed by Borsa Italiana) with respect to the static price (the static price shall be the previous day s reference price, in the opening auction, or the auction price, in the continuous trading phase); and (ii) ± 3.5% (or such other amount established by Borsa Italiana in the "Guide to the Parameters") with respect to the dynamic price (the price of the last contract concluded during the continuous trading phase). Where the price of a contract that is being concluded exceeds one of the price variation limits referred to above, trading in that security will be automatically suspended and a volatility auction phase begun for a certain period of time.

Markets

The Consob is the public authority responsible for regulating and supervising the Italian securities markets to ensure the transparency and regularity of the dealings and protect the investing public. Borsa Italiana, which is part of London Stock Exchange Group, following the merger effective October 1, 2007, is a joint stock company authorized by Consob to operate, inter alia, regulated markets in Italy; it is responsible for the organization and management of the Italian stock exchange. One of the fundamental characteristics of the financial market organization in Italy is the separation of responsibility for supervision (Consob and the Bank of Italy) from that of market management (Borsa Italiana). Main responsibilities of Borsa Italiana are the admission, exclusion and suspension of financial instruments and intermediaries to and from trading and the surveillance of the markets.

According to Consob regulations, Borsa Italiana has issued rules governing the organization and management of the Italian Regulated Markets it is responsible for, which are MTA (shares, convertible bonds, pre-emptive rights, warrants and Funds), ETFplus (Exchange Traded Funds and Exchange Traded Commodities market), IDEM (index and stock derivatives market), SeDeX (covered warrants and certificates), MOT (bond market) and MIV (market for investment vehicles), as well as the admission to listing on and trading on these markets.

According to EU Markets in Financial Instruments Directive (No. 2004/39/EC) (MiFID) and Consob regulations, orders can be routed not only to Regulated Markets but also to either Multilateral Trading Facilities (MTFs) or Systematic Internalisers. A MTF is a multilateral system, operated by an investment firm or a market operator, which brings together multiple third-party buying and selling interests in financial instruments in the system and in accordance with non-discretionary rules in a way that results in a contract. A Systematic Internaliser is an investment firm or a bank which deals on own account by executing client orders outside a Regulated Market or a MTF. Outside Regulated Markets, block trading is also permitted for orders that meet certain minimum size requirements and must be notified to Consob and Borsa Italiana.

According to Legislative Decree No. 58 of February 24, 1998 (Decree No. 58 , the Consolidated Law on Financial Intermediation), the provision of investment services and activities to the public on a professional basis is reserved to banks and investment firms (authorized persons). The Bank of Italy and Consob shall exercise supervisory

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powers over authorized persons. They shall each supervise the observance of regulatory and legislative provisions according to their respective responsibilities. In particular, in connection with the pursuance of the safeguarding of faith in the financial system, the protection of investors, the stability and correct operation of the financial system, the competitiveness of the financial system and the observance of financial provisions, the Bank of Italy shall be responsible for risk containment, asset stability and the sound and prudent management of intermediaries whilst Consob shall be responsible for the transparency and correctness of conduct.

The Bank of Italy, in agreement with Consob, also regulates the operation of the clearing and settlement service for transactions involving financial instruments. The regulations and measures of general application adopted by Consob and the Bank of Italy are available on the website of Consob (www.consob.it) or Bank of Italy (www.bancaditalia.it).

The regulations adopted by Borsa Italiana are available on its website (www.borsaitaliana.it).

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Item 10. ADDITIONAL INFORMATION

Memorandum and Articles of Association

Register office

"Eni SpA" is the company resulting from the privatization of Ente Nazionale Idrocarburi, a public agency, established by Law No. 136 of February 10, 1953 and it is registered in the Rome Companies Register, with identification number (and tax number) 00484960588, and VAT number 00905811006. The Company s registered office is in Rome, Italy, and the Company has two branch offices in San Donato Milanese (Milan).

The full text of Eni s By-laws is attached as an exhibit to this Annual Report (last amended on February 14, 2013). See "Exhibit 1".

Company objects and purpose
In accordance with Article 4 of Eni s By-laws, the Company purpose includes the direct and/or indirect exercise, through equity holdings in companies or other entities of: activities in the field of hydrocarbons and natural gases, in compliance with the terms of concessions provided for by law; activities in the field of chemicals, nuclear fuels, geothermal energy, renewable energy sources and energy in general, in the design and construction of industrial plants in the mining industry, in the metallurgy industry, in the textile machinery industry, in the water sector, including water diversion, potabilization, purification, distribution and reuse; in the environmental protection sector and in the treatment and disposal of waste, as well as any other economic activity that is instrumental, ancillary or complementary to the afore mentioned activities. The Company performs and manages the technical and financial coordination of subsidiaries and associated companies and provides financial assistance to them. Moreover, the Company may acquire equity holdings and interests in other companies or enterprises with corporate purposes that are similar, related or complementary to its own or those of companies in which it has equity holdings, either in Italy or abroad, and it may provide secured and/or unsecured guarantees for its own and others obligations, including, in particular, sureties.

Directors issues

The Eni s Board of Directors is invested with the fullest powers for the ordinary and extraordinary management of the Company and, in particular, the Board has the power to perform all acts it deems advisable for the implementation and achievement of the corporate purpose, with the sole exception of acts that the law or Eni s By-laws reserve to the Shareholders Meeting.

If the Shareholders Meeting has not appointed a Chairman of the Board, the Board shall elect one from among its members.

The Board of Directors appoints a Chief Executive Officer and delegates to him all necessary powers for the management of the Company, with the exception of those powers that cannot be delegated in accordance with current legislation and those retained exclusively by the Board of Directors on matters regarding major strategic, operational and organizational decisions.

According to Eni s By-laws, the Board of Directors may delegate powers to the Chairman to identify and promote integrated projects and international agreements of strategic importance.

The Board of Directors may at any time revoke the powers delegated, proceeding, in the case of revocation of the powers delegated to the Chief Executive Officer, to appoint another Chief Executive Officer at the same time.

The Board of Directors, acting upon a proposal of the Chairman and in agreement with the Chief Executive Officer, may confer powers for individual acts or categories of acts on other members of the Board of Directors.

In accordance with Eni s By-laws, for a Board meeting to be valid, a majority of serving Directors with voting rights must be present. Resolutions shall be approved by a majority of the votes of the Directors with voting rights present; in the event of a tie, the person who chairs the meeting shall have a casting vote.

Interests in Company s transactions

As provided by the Italian Civil Code, when a Director retains a personal interest or an interest on behalf of third parties in Company transactions, he shall disclose it to the Board of Directors and to the Board of Statutory Auditors, specifying the nature, terms, origin and extent of such interest. Based on this provision and in compliance with the Consob regulation on transactions with related parties (the "Consob Regulation"), the Board of Directors on

November 18, 2010 unanimously approved the Management System Guidelines "Transactions involving interests of directors and statutory auditors and transactions with related parties"[22], which has been in effect from January 1, 2011[23] to ensure the transparency and substantial and procedural fairness of transactions with related parties and with parties that are of interest to Eni s Directors and Statutory Auditors, carried out by Eni itself or its subsidiaries. This MSG and the subsequent amendments received the preliminary favorable opinion, expressed unanimously, of the Control and Risk Committee, composed entirely of independent Directors as per the requirements set out in the Corporate Governance Code, which Eni has adopted, and in accordance with the Consob Regulation. The MSG sets out monitoring and evaluation requirements for the preliminary phase and for carrying out a transaction with a party in which a Director or Statutory Auditor has an interest. In this regard, both in the preliminary and deliberation phase, a thorough, documented examination of the reasons for the transaction, highlighting the Company s interest in carrying it out and the soundness and fairness of the underlying terms, is required. Directors involved in matters subject to Board resolution normally shall not participate in the relevant discussion and decision and must leave the room during these procedures. If the person involved is the Chief Executive Officer and the transaction falls under his duties, he shall in any case abstain from taking part in the transaction and shall entrust the matter to the Board of Directors (as provided by Article 2391 of the Italian Civil Code). In any case, if the transaction is the responsibility of the Board of Directors of Eni, a non-binding opinion from the Control and Risk Committee is required.

Moreover, to ensure compliance with the investigation and resolution procedures envisaged by the above mentioned MSG, Directors and Statutory Auditors issue a declaration, every six months and/or when there is any change, in which they explain their potential interests related to Eni and its subsidiaries, and in any case they inform the CEO (or the Chairman, in the case the CEO holds an interest) about individual transactions that Eni intends to carry out in which they have an interest; the CEO (or Chairman) will then inform the other Directors and the Board of Statutory Auditors.

Compensation

Directors compensation shall be determined by the Shareholders Meeting, as required by Italian law, while the compensation of Directors assigned particular duties in accordance with the By-laws (such as the Board Chairman and the CEO), or that participate in Board Committees, shall be determined by the Board of Directors, upon the proposal of the Compensation Committee, after consultation with the Board of Statutory Auditors (for more details about the compensation policy in 2012, see "Item 6 Compensation").

Borrowing powers

The power to borrow is included in the Company purpose. Moreover, in accordance with Article 11 of the By-laws, the Company may issue bonds, including convertibles bonds and warrants, in compliance with the law.

Retirement and shareholdings

There are no provisions in the By-laws relating to either retirement based on age-limit requirements and the number of shares required for a Director to qualify.

Company s shares

In accordance with Article 5 of the By-laws, the Company s share capital amounts to euro 4,005,358,876.00, fully paid, and is represented by 3,634,185,330 ordinary registered shares without indication of par value. As required by the Italian law on the dematerialization of financial instruments, Eni s shares (the "Shares") must be held with "Monte Titoli SpA" (the Italian Central Securities Depository) and their beneficial owners may exercise their rights through special deposit accounts opened with intermediaries, such as banks, brokers and securities dealers.

Shares are indivisible and each share is entitled to one vote. Shareholders are allowed to vote at ordinary and extraordinary Shareholders Meeting, including by proxy or by mail or, if envisaged in the notice calling the Meeting, by electronic means.

Moreover, in accordance with Article 9 of the By-laws, the Shareholders Meeting may resolve to increase the Company share capital by issuing shares, including shares of different classes, to be granted for no consideration to Eni employees, pursuant to Article 2349 of the Italian Civil Code. This power has not been exercised.

(22) The Board of Directors modified this Management System Guideline on January 19, 2012.
(23) This MSG replaced the previous regulation issued by the Board of Directors on the matter on February 12, 2009. The new provisions regarding information to be provided to the public, under both the Consob Regulation and the MSG, are applicable from December 1, 2010.

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In 1995, Eni established a sponsored American Depositary Receipts program directed at U.S. investors.

Each Eni ADR is equal to two Eni ordinary shares; Eni ADRs are listed on the NYSE.

Dividend rights
Shareholders have the right to participate in profits and any other rights as provided by the law and subject to any applicable legal limitations. Specifically, the ordinary Shareholders Meeting called to approve the annual financial statements may allocate the net income resulting after allotment to the legal reserve to the payment of a final dividend per share. In addition, during the course of the financial year, the Board of Directors may distribute, as allowed by the By-laws, interim dividends to the shareholders. Entitlement to dividends not collected within five years of the day on which they become payable shall lapse in favor of the Company and such dividends shall be allocated to reserves.

Voting rights
The general provisions on share "voting rights" are described at the paragraph "Shareholders Meeting" below. In relation to the appointment of the Board of Directors (Eni s Board is not a "staggered board") and the Board of Statutory Auditors (see Item 6), Eni s By-laws provide for a slate voting system. In particular, pursuant to Article 17 of the By-laws and in accordance with applicable law, slates may be presented both by shareholders, either severally or jointly, representing at least 1% of the share capital, or any other threshold established by Consob in its regulation, or by the Board of Directors. Each shareholder may, severally or jointly, submit and vote on a single slate only.

There are no provisions in Eni s By-laws relating to: rights to share in Company profits; redemption provisions; sinking fund provisions; liability to further capital calls by the Company.

Liquidation rights
In the event the Company is wound up, the Shareholders Meeting shall decide the manner of its liquidation and appoint one or more liquidators, establishing their powers and remuneration. In accordance with Italian law, shareholders would be entitled to the distribution of the remaining liquidated assets of the Company in proportion to their shareholdings, only after payment of all the Company s liabilities and satisfaction of all other creditors.

Change in shareholders rights

A shareholders resolution is required to make changes in shareholders rights. Italian law gives shareholders the right to withdraw in the event of an amendment of the provisions of the By-laws relating to, among other matters, voting and dividend rights, approved by resolution of the Shareholders Meeting with the attendance and decision-making quorum established by law for extraordinary meetings.

Shareholders Meeting

The Shareholders Meeting resolves on the issues set forth by applicable law and Eni s By-laws, in "ordinary" or "extraordinary" form. Resolutions of ordinary and extraordinary Shareholders Meetings in first, second or third call must be passed with the majorities required by law in each case. The Board of Directors may, if deemed necessary, establish that both the ordinary and the extraordinary Shareholders Meeting be held after a single call. In the case of a single call, the majorities required by law in this case shall apply.

Shareholders Meetings shall normally be held at the Company s registered office, unless otherwise decided by the Board of Directors, provided however they are held in Italy.

The Shareholders Meeting shall be called by way of a notice published on the Company website, as well as in accordance with the procedures specified in Consob regulations, by the statutory deadlines and in accordance with applicable law. The notice calling the meeting, the content of which content is defined by the law and Eni s By-laws, contains all the information for attending and voting at the meeting, including information on proxy voting and voting by correspondence (the information is also available on the Company s website) and, if envisaged, it may include instructions for participating in the Shareholders Meeting by means of telecommunication systems, as well as exercising the right to vote by electronic means. By the same date of the publication of the notice calling the Meeting, the Board of Directors shall make a report on each of the items on the agenda available to the public at the Company s registered office, on the Company s website and by other means envisaged by Consob regulations. Specific legal provisions may require other terms of publication of the Board of Directors report (i.e. in case of extraordinary transactions). An ordinary Shareholders Meeting shall be called at least once a year, within 180 days of the end of the Company s financial year (on December 31), to approve the financial statements, since the Company is required to draw up Consolidated Financial Statements.

The right to attend and cast a vote at the Shareholders Meeting shall be certified by a statement submitted by an authorized intermediary on the basis of its accounting records to the Company on behalf of the person entitled to vote. The statement shall be issued by the intermediary on the basis of the balances on the accounts recorded at the end of the seventh trading day prior to the date of the Shareholders Meeting. Credit and debit records entered on the accounts after this deadline shall not be considered for the purpose of determining entitlement to exercise voting rights at the Shareholders Meeting. The statement, issued by the authorized intermediary, must reach the Company by the end of the third trading day prior to the date of the Shareholders Meeting, or by any other deadline established by Consob regulations issued in agreement with the Bank of Italy. Shareholders shall nevertheless be entitled to attend the Meeting and cast a vote if the statements are received by the Company after the deadlines indicated above, provided they are received before the start of proceedings of the given call. For the purposes of these provisions, reference is made to the date of first call, provided that the dates of any subsequent calls are indicated in the notice calling the Meeting; otherwise, the date of each call is deemed the reference date.

Those persons who are entitled to vote may appoint a party to represent themselves at the Shareholders Meeting by means of a written proxy or in electronic form in the manner set forth by current law. Electronic notification of the proxy may be made through a special section of the Company website as indicated in the notice calling the Meeting. In order to simplify proxy voting by shareholders who are employees of the Company or of its subsidiaries and belong to shareholders associations that meet applicable statutory requirements, locations for communications and collection of proxies shall be made available to in accordance with the terms and conditions agreed from time to time with the legal representatives of said associations.

The right to vote may also be exercised by correspondence in accordance with the applicable laws and regulations. If provided for in the notice calling the meeting, those persons entitled to vote may participate in the Shareholders Meeting by means of telecommunication systems and exercise their right to vote by electronic means in accordance with the provisions of the law, applicable regulations and the Shareholders Meeting Rules.

The Company may designate a person for each Shareholders Meeting to whom the shareholders may confer a proxy with voting instructions on all or some of the items on the agenda, as provided for by applicable laws and regulations, by the end of the second trading day preceding the date set for the Shareholders Meeting including for calls subsequent to the first. Such proxy shall not be valid for items in respect of which no voting instructions have been provided.

The Chairman of the meeting shall verify the validity of proxies and, in general, entitlement to participate in the Meeting.

The Shareholders Meetings are governed by the Shareholders Meeting Rules as approved by resolution of the ordinary Shareholders Meeting on December 4, 1998, in order to guarantee an efficient conduct of meetings and the right of each shareholder to express his or her opinion on the items on the agenda.

During Shareholders Meetings, the Board of Directors provides broad disclosure on items examined and shareholders can request information on issues in the agenda. Information is provided taking into account applicable rules on inside information.

Stock ownership limitation and voting rights restrictions

There are no limitations imposed by Italian law or by Eni s By-laws on the rights of non-residents in Italy or foreign persons to hold shares or vote other than the limitations described below (which are equally applicable to both residents and non-residents of Italy).

In accordance with Article 6 of the By-laws, and in application of the special rules pursuant to Article 3[24] of Decree Law No. 332 of May 31, 1994, ratified with amendments by Law No. 474 of July 30, 1994 (Law No. 474/1994), no shareholder may hold, in any capacity, directly or indirectly, more than 3% of the Company s share capital. Any voting rights and any other non-financial rights attached to shares held in excess of the maximum limit indicated above may not be exercised and the voting rights of each shareholder to whom such limit applies shall be reduced in proportion, unless otherwise jointly specified in advance by the parties involved.

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(24) This provision has been modified by the Decree Law No. 21 of March 15, 2012, ratified with amendments by Law No. 56 of May 11, 2012. For more details see the paragraph "Limitation on changes in control of the Company (Special Powers of the Italian State)" below.

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Pursuant to Article 32 of the By-laws and the above mentioned provision of law, shareholdings owned by the Ministry of the Economy and Finance, public entities or organization controlled by them are exempt from this ban.

Finally, this special rule provides that the clause regarding shareholding limits will lose effect if the limit is exceeded as a result of a take-over bid, provided that, as a result of the takeover, the bidder will own a shareholding of at least 75% of the share capital with the right to vote on resolutions concerning the appointment or dismissal of Directors.

Limitation on changes in control of the Company (Special Powers of the Italian State)

Pursuant to Article 6.2 of the By-laws and to the special rules set out in Law No. 474/1994, the Minister of the Economy and Finance, in agreement with the Minister of Economic Development, retains special powers that can be exercised in accordance with the criteria set out in the Decree issued by the President of the Council of Ministers on June 10, 2004.

These special powers consist of the:

(a) power of opposition to the acquisition of material shareholdings (i.e. shareholdings that represent, directly and indirectly, at least 3% of the share capital and consist of shares with the right to vote in ordinary Shareholders Meetings). The opposition, duly justified, must be expressed if the transaction is deemed to be prejudicial to the vital interests of the State, within ten days of the date of the notice to be filed by the Directors at the time request is made for registration in the shareholders register. Pending expiry of the ten-day term, the voting rights and other rights, except for the right to participate in profits, attached to the shares that represent the material shareholding may not be exercised. In the event the right of opposition is exercised, by means of a duly justified decision based on the actual prejudicial effect caused by the transaction to the vital interests of the State, the transferee may not exercise the voting rights or any other non-financial rights attached to the shares representing the material shareholding, and must dispose of said shares within one year. In the event of a failure to comply, the Court, upon appeal of the Minister of the Economy and Finance, shall order the disposal of the shares representing the material shareholding in accordance with the procedures set out in Article 2359-*ter* of the Italian Civil Code;

(b) power of opposition to the conclusion of shareholders agreements, as referred to in Article 122 of the Consolidated Law on Finance, involving at least 3% of the share capital with voting rights at the ordinary Shareholders Meetings. For the purpose of exercising said power of opposition, Consob shall notify the Minister of the Economy and Finance of any such agreements notified to it pursuant to Article 122 of the Consolidated Law on Finance. The power of opposition shall be exercised within ten days of the date of the notice from Consob. Pending expiry of the ten-day term, the voting rights and other non-financial rights attached to the shares held by the shareholders who have entered into such shareholders agreements may not be exercised. If the power of opposition is exercised, with a measure duly explicating the prejudice that the aforesaid agreements may cause to the vital interests of the Italian State, the shareholders agreement shall be null and void. If the conduct during the Shareholders Meeting of the shareholders bound by the agreement reveals that the undertakings given under an agreement pursuant to the aforesaid Article 122 of the Consolidated Law on Finance have been maintained, any resolutions passed with the casting vote of these same shareholders may be challenged;

(c) power of veto, duly justified by the effective prejudice to the vital interests of the Italian State, with respect to resolutions to wind up the Company, to transfer the business, to merge, to demerge, to transfer the Company s registered office abroad, to change the Company purpose or to amend the By-laws so as to eliminate or modify the powers set out in letters (a), (b), (c) and in the subsequent letter (d); and

(d) power of appointment of one non-voting Director.

The decisions for exercising the powers detailed in letters (a), (b) and (c) may be challenged, within sixty days, by the parties entitled to do so, before the Regional Administrative Court of Lazio.

The special powers shall be exercisable respect to cases significant and general public interest (such as public order, public security, public health and defense) in an appropriate way and measure and proportionally to the safeguarding of these interests, even by means of necessary time limits, without prejudice to compliance with national and European principles and, in particular, with the non-discrimination principle.

The Decree of the Italian Prime Minister of May 20, 2010, following on certain decisions of the European Court of Justice, repealed Article 1, paragraph 2 of the Decree issued by the Italian Prime Minister on June 10, 2004, related to the specific circumstances in which the special powers may be exercised.

Law Decree No. 21 of March 15, 2012, ratified with amendments by Law No. 56 of May 11, 2012, modified Italian legislation governing the special powers of the State to comply with European rules. The previous provisions (Article 2 of Law Decree No. 332/1994 ratified by Law No. 474/1994 and its implementing decrees), as well as the provisions of the By-laws which are inconsistent with the new rules, will be repealed by the last of the implementing ministerial regulations in the areas of energy, transport and communications. If the afore mentioned implementing decrees, approved on March 14, 2014 by the Italian Council of Ministers, came into force at the date of the approval of the present Form, the provisions set forth in Article 2 of the Law Decree No. 332/1994 would be repealed. The provisions regarding the stock ownership limitations and voting rights restrictions pursuant to Article 3 of Law No. 474/1994 remain in force.

In order to "promote privatization and the spread of investment in shares" of companies in which the Italian State has a significant shareholding, Article 1, paragraphs 381 to 384 of Law No. 266 of 2005 (2006 Financial Law) introduced the power to add provisions to the By-laws of privatized companies primarily controlled by the Italian State, like Eni, which allow shares or participating financial instruments to be issued that grant the special meeting of its holders the right to request that new shares, even at par value, or new financial instruments be issued to them with the right to vote in ordinary and extraordinary Shareholders Meetings. Making this amendment to the By-laws would lead to the shareholding limit referred to in Article 6.1 of the By-laws being removed. At the present time, however, Eni s By-laws do not contain such any provision.

Shareholder ownership thresholds

There are no By-law provisions governing the disclosure of the ownership threshold because the matter is regulated by Italian law. Pursuant to the Consolidated Law on Finance[25] and Consob Regulation[26], any direct or indirect holding in the voting shares of an Italian listed company in excess of 2%[27], 5%, 10%, 15%, 20%, 25%, 30%, 50%, 66.6%, 90% and 95% must be notified to the investee company and to Consob. The same disclosure requirements refer to holdings that drop below one of the specified thresholds. Due declarations shall be made within five trading days of the date of the transaction triggering the obligation to notify, regardless of the date on which it is carried out, using the forms established in Annex 4A to the above mentioned Regulation.

The relevant thresholds noted above shall be calculated including: (i) shares owned by the reporting person, even if the voting rights belong or are assigned to third parties, or are suspended, as well as shares in which the voting rights belong or are assigned to him; and (ii) shares held through third parties (and shares whose voting rights are assigned to such third parties) such as nominees, trustees or subsidiary companies. The obligation to notify also applies to any direct or indirect holding owned through ADRs. Specific disclosure requirements (with partially different thresholds) are connected to so-called "potential holdings" (such as holdings of derivatives or other equity-linked securities).

Voting rights attached to listed shares which have not been notified pursuant to the above mentioned disclosure requirements may not be exercised. Any resolution or act adopted in violation of such limitation, with the contribution of those undisclosed shares, could be voided if challenged in Court, under the Italian Civil Code.

According to the Italian Civil Code (Article 2359-*bis*), a subsidiary may acquire shares of the parent company only within the limits of distributable profits and available reserves as resulting from the last approved balance sheet. Only fully-paid shares can be purchased. The purchase must be approved by the Shareholders Meeting and, in any case, the nominal value of shares purchased may not exceed one-fifth of the capital of the parent company if the latter is a listed company taking into account for this purpose the shares held by the same parent company or its subsidiaries.

The Consolidated Law on Finance provides rules governing cross-holdings. In particular, except for the cases contemplated by the above mentioned Article 2359-*bis* of the Italian Civil Code, in case of a reciprocal participation exceeding the limit of 2% of the shares, the company that last exceeds the limit successively cannot exercise its right to vote relative to the shares held in excess of such threshold and must sell such shares within the following 12 months. In the event of failure to dispose of the shares by such time limit, the voting rights shall be suspended with respect to the entire shareholding, and any resolution or act adopted with the contribution of the relevant shares may be challenged under the Italian Civil Code. If a person holds an interest exceeding 2% of the share capital of a listed company, such listed company or any entity controlling such listed company may not acquire an interest exceeding 2% of the share capital of a listed company controlled by the former. If the foregoing limit is exceeded, the person who last exceeded the foregoing limit (or both holders, if it is not possible to ascertain which of the two persons was the last to exceed the limit) may not exercise the voting rights attached to the shares exceeding the foregoing limit. In the event of non-compliance, the voting rights attached to the shares held in excess of the limit specified shall be suspended and any resolution or act adopted with the contribution of the relevant shares may be challenged under the Italian Civil Code. The limitations described above are not applicable in the case of a takeover bid or exchange tender offer to acquire at least 60% of the ordinary shares of a listed company.

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(25) Legislative Decree No. 58 of February 24, 1998, with specific reference to Articles 120-122.

(26) Article 117 of Consob Decision No. 11971/1999 and subsequently amendments.

(27) Moreover, Consob may, by means of measures justified by the need to protect investors, as well as corporate control market and capital market efficiency and transparency, envisage for a limited period of time thresholds lower than 2% by its decree for companies with an elevated current market value and, particularly, extensive shareholding structure.

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Under the Consolidated Law on Finance, any agreement, in any form, regarding the exercise of voting rights in a listed company or in its parent company, must be, within five days of stipulation: (i) notified to Consob; (ii) published in abstract form, in the Italian daily press; (iii) filed in the Register of Companies in which the listed company is registered; and (iv) notified to the company with listed shares. In the event of non-compliance with these requirements, the agreements shall be null and void and the voting rights attached to the relevant shares may not be exercised and any resolution or act adopted with the contribution of such shares may be challenged under the Italian Civil Code.

The same provisions also apply to agreements, in any form, that: (a) create obligations of consultation prior to the exercise of voting rights in a listed company and in its controlling companies; (b) set limits on the transfer of the related shares or of other financial instruments that entitle holders to buy or subscribe them; (c) provide for the purchase of the shares or of the above mentioned financial instruments; (d) have as their object or effect the exercise, jointly or otherwise, of dominant influence on such companies; and (d-*bis*) which aim to encourage or frustrate a takeover bid or an exchange tender offer, including commitments relating to non-participation in a takeover bid.

Finally, in accordance with Law No. 287 of October 10, 1990, any merger or acquisition of sole or joint control over a company that would create or strengthen a dominant position in the domestic market in a manner that eliminates or significantly reduces competition is prohibited and mergers and acquisition of specified dimension must be subject to the prior authorization of the Italian Antitrust Authority[28]. However, if the acquiring party and the company to be acquired operate in more than one EU Member State and together exceed certain revenue thresholds, the antitrust approval for the acquisition falls under the exclusive jurisdiction of the European Commission.

Changes in share capital

Eni s By-laws do not provide for more stringent conditions than are required by law.

Share capital increases are resolved by a shareholders resolution at an extraordinary Shareholders Meeting. Under Italian law, shareholders have a pre-emptive right to subscribe to newly issued of shares and corporate bonds convertible into shares in proportion to their respective shareholdings. If the Company s interest so requires, the pre-emptive right may be waived or limited by the shareholders resolution authorizing the share capital increase. The shareholders pre-emptive right is also waived if the shareholders resolution authorizing the share capital increase provides for the subscription of new issues of shares in the form of contributions in-kind.

Material contracts

None.

Exchange controls

There are no exchange controls in Italy. Residents and non-residents in Italy may carry out any investments, divestments and other transactions that entail a transfer of assets to or from Italy, subject only to the reporting, record-keeping and disclosure requirements described below. In particular, residents of Italy may hold foreign currency and foreign securities of any kind, within and outside Italy, while non-residents may invest in Italian securities without restriction and may export from Italy cash, instruments of credit or payment and securities, whether in foreign currency or euro, representing interest, dividends, other asset distributions and the proceeds of dispositions.

Updated reporting and record-keeping requirements are contained in the Italian legislation which implements an EU directive regarding the free movement of capital. Such legislation requires that transfers into or out of Italy of cash or securities in excess of euro 12,500 be reported in writing to the relevant authority (Ministry of Economy and Finance) by residents or non-residents that effect such transfers directly, or by banks, securities dealers or Poste Italiane SpA (Italian Mail) that effect such transactions on their behalf. In addition, banks, securities dealers or Poste Italiane SpA effecting such transactions on behalf of residents or non-residents of Italy are required to maintain records of such transactions for five years. These records may be inspected at any time by Italian tax and judicial authorities.

(28) Autorità garante per la concorrenza ed il mercato (AGCM - www.agcm.it).

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Non-compliance with these reporting and record-keeping requirements may result in administrative fines or, in the case of false reporting and in certain cases of incomplete reporting, criminal penalties.

Taxation

The information set forth below is only a summary; Italian, the United States and other tax laws may change from time to time. Holders of shares and ADRs should consult with their professional advisors as to the tax consequences of their ownership and disposition of the shares and ADRs, including, in particular, the effect of tax laws of any other jurisdiction.

Italian taxation

The following is a summary of the material Italian tax consequences of the ownership and disposition of shares or ADRs as at the date hereof and does not purport to be a complete analysis of all potential tax effects relevant to the ownership or disposition of shares or ADRs.

Income tax

Dividends received by Italian resident individuals in relation to interest exceeding 2% of the voting rights or 5% of the share capital ("substantial interest") are included in the taxable income subject to personal income tax to the extent of 49.72% of their amount. Personal income tax applies at progressive rates ranging from 23% to 43% plus local surtaxes. Dividends received by Italian resident individuals in relation to non-substantial interest not related to the conduct of a business are subject to a substitute tax of 20% withheld at the source by the dividend paying agent. This being the case, the dividend is not to be included in the individual s tax return. If the non-substantial interest is related to the conduct of a business, dividends received in respect of 2013 profits are included in the taxable business income for 49.72% of their amount.

Despite the above statement, dividends are included in the taxable income at 40% to the extent they relate to un distributed profit of 2007 and previous years.

Dividends received by Italian investment funds, foreign open-ended investment funds authorized to market their securities in Italy pursuant to the Law Decree June 6, 1956, No. 476, converted into Law July 25, 1956, No. 786, and *società di investimento a capitale variabil*e (SICAV) are not subject to substitute tax but are included in the aggregate income of the investment fund or SICAV. The investment fund or SICAV will not be subject to tax on the dividends. A withholding tax of 20% may apply on income of the investment fund or SICAV derived by unitholders or shareholders through distribution and/or upon redemption or disposal of the units and shares.

Dividends received by real estate funds to which the provisions of Law Decree No. 351 of September 25, 2001, as subsequently amended, apply, are not subject to any substitute tax nor to any other income tax in the hands of the fund.

The income of the real estate fund is subject to tax, in the hands of the unitholder, depending on status and percentage of participation, or, when earned by the fund, through distribution and/or upon redemption or disposal of the units.

Dividends received by a pension fund (subject to the regime provided for by Article 17 of the Italian Legislative Decree No. 252 of December 5, 2005) and deposited with an authorized intermediary, will not be subject to substitute tax, but must be included in the result of the relevant portfolio accrued at the end of the tax period, to be subject to an 11% substitute tax.

Dividends paid to non-Italian residents are subject to the same substitute tax levied at source by the dividend paying agent at the rate of 20%, provided that the interest is not connected to an Italian permanent establishment. Up to one fourth of the substitute tax withheld might be recovered by the non-resident shareholder from the Italian Tax Authorities upon provision of evidence of full payment of income tax on such dividend in his/her country of residence in an amount at least equal to the total refund claimed.

Dividends are subject to a 1.375% substitute tax introduced by the Financial Bill for 2008 where the conditions in Article 27, paragraph 3-*ter*, Presidential Decree No. 600 of 1973 are met, i.e. dividends are paid to companies and entities subject to a corporate income tax in a European Union member state or in Norway.

The substitute tax may also be reduced under the tax treaty in force between Italy and the country of residence of the Beneficial Owner of the dividend. Italy has executed income tax treaties with approximately 70 foreign countries, including all EU Member States, Argentina, Australia, Brazil, Canada, Japan, New Zealand, Norway, Switzerland, the United States and some countries in Africa, the Middle East and the Far East. Generally speaking, it should be noted that tax treaties are not applicable where the holder is a tax-exempt entity or, with few exceptions, a partnership or a trust.

In order to obtain the treaty benefit of a reduced substitute tax rate at the same time of payment, the Beneficial Owner must file an application to the dividend paying agent chosen by the Depositary stating the existence of the conditions for the applicability of the treaty benefit, together with a certification issued by the foreign tax authorities stating that the shareholder is a resident of that country for treaty purposes.

Under the tax treaty between the United States and Italy, dividends derived and beneficially owned by a U.S. resident who holds less than 25% of the Company s shares are subject to an Italian withholding or substitute tax at a reduced rate of 15%, provided that the interest is not effectively connected with a permanent establishment in Italy through which the U.S. resident carries on a business or a fixed establishment in Italy through which such U.S. resident performs independent personal services (for further details please refer to the relevant provisions set forth in the Italy U.S. Tax Treaty). In the absence of such conditions, the dividend paying agent will deduct from the gross amount of the dividend the substitute tax at the statutory rate of 20%. Based on the certification procedure required by the Italian Tax Authorities, to benefit from the direct application of the 15% substitute tax the U.S. shareholder must provide the dividend paying agent with a certificate obtained from the U.S. Internal Revenue Service (the IRS) with respect to each dividend payment. The request for this certificate must include a statement, signed under penalty of perjury, attesting that the shareholder is a U.S. resident individual or corporation, and does not maintain a permanent establishment in Italy, and must set forth other required information. The normal time for processing requests for certification by the IRS is normally about six to eight weeks.

Where the Beneficial Owner has not provided the above mentioned documentation, the dividend paying agent will deduct from the gross amount of the dividend the substitute tax at the statutory rate of 20%. The U.S. recipient will then be entitled to claim from the Italian Tax Authorities the difference (treaty refund) between the domestic rate and the treaty one by filing specific forms (certificate) with the Italian Tax Authorities.

As reflected in the Deposit Agreement, if any tax or other governmental charge shall become payable by or on behalf of the Custodian or the Depositary with respect to an ADR, any Deposited Securities represented by the American Depositary Shares (ADSs), such tax or other governmental charge shall be paid by the Holder hereof to the Depositary. The Depositary may refuse to effect any registration, registration of transfer, split-up or combination hereof or any withdrawal of such Deposited Securities until such payment is made. The Depositary may also deduct from any distributions on or in respect of Deposited Securities, or may sell by public or private sale for the account of the Holder hereof any part or all of such Deposited Securities (after attempting by reasonable means to notify the Holder hereof prior to such sale), and may apply such deduction or the proceeds of any such sale in payment of such tax or other governmental charge, the Holder hereof remaining liable for any deficiency, and shall reduce the number of ADSs to reflect any such sales of shares. Pursuant to the Deposit Agreement, the Depositary and the Custodian may make and maintain arrangements to enable persons that are considered United States residents for purposes of applicable law to receive any tax rebates (pursuant to an applicable treaty or otherwise) or other tax related benefits relating to distributions on the ADSs to which such persons are entitled. Notwithstanding any other terms of the Deposit Agreement or the ADR, absent the gross negligence or bad faith of, respectively, the Depositary and the Company, the Depositary and the Company assume no obligation, and shall not be subject to any liability, for the failure of any Holder or Beneficial Owner, or its agent or agents, to receive any tax benefit under applicable law or tax treaties. The Depositary shall not be liable for any acts or omissions of any other party in connection with any attempts to obtain any such benefit, and Holders and Beneficial Owners hereby agree that each of them shall be conclusively bound by any deadline established by the Depositary in connection therewith.

Capital gains tax

This paragraph concerns and applies to capital gains out of the scope of a business activity carried out in Italy.

Profits gained by Italian resident individuals upon the sale of a substantial interest are included in the taxable base subject to personal income tax for 49.72% of their amount, while gains realized upon the sale of non-substantial interest is subject to a substitute tax at a 20% rate.

For gains deriving from the sale of non-substantial interest, two different systems may be applied at the option of the shareholder as an alternative to the filing of the tax return:

- the so-called "administered savings" tax regime (*risparmio amministrato*), based on which intermediaries acting as shares depositaries shall apply a substitute tax (20%) on each gain, on a cash basis. If the sale of shares generated a loss, said loss may be carried forward up to the fourth following year; and the so-called "portfolio management" tax regime (*risparmio gestito*) which is applicable when the shares form part of a portfolio managed by an Italian asset management company. The accrued net profit of the portfolio is subject to a 20% substitute tax to be applied by the portfolio.

Gains realized by non-residents from non-substantial interest in listed companies are deemed not to be realized in Italy and consequently are not subject to the capital gains tax.

On the contrary, gains realized by non-residents from substantial interests even in listed companies are deemed to be realized in Italy and consequently are subject to the capital gains tax.

However, double taxation treaties may eliminate the capital gains tax. Under the income tax convention between the United States and Italy, a U.S. resident will not be subject to the capital gains tax unless the shares or ADRs form part of the business property of a permanent establishment of the holder in Italy or pertain to a fixed establishment available to a shareholder in Italy for the purposes of performing independent personal services. U.S. residents who sell shares may be required to produce appropriate documentation establishing that the above mentioned conditions of non taxability pursuant to the convention have been satisfied.

Financial Transactions Tax

Italian Law No. 228 of December 24, 2012, has introduced a Financial Transactions Tax which applies to the transfer of shares, ADR and other financial instruments issued by companies resident in Italy. The tax rate applicable for financial year 2013 is 0.12% for ADR negotiated in regulated markets (like the NYSE). For further years, the tax rate will be reduced to 0.10%. This tax applies to transactions carried out from March 1, 2013.

Non-Italian intermediaries, involved in the transactions of Eni ADR, must withhold and pay the Financial Transactions Tax. For this purpose, non-Italian intermediaries can appoint an Italian Tax Representative, according to the Italian tax law.

Inheritance and gift tax

Pursuant to Law Decree No. 262 of October 3, 2006, converted with amendments by Law No. 286 of November 24, 2006 effective from November 29, 2006, and Law No. 296 of December 27, 2006, the transfers of any valuable assets (including shares) as a result of death or donation (or other transfers for no consideration) and the creation of liens on such assets for a specific purpose are taxed as follows:

(a) 4 per cent: if the transfer is made to spouses and direct descendants or ancestors; in this case, the transfer is subject to tax on the value exceeding euro 1,000,000 (per beneficiary);
(b) 6 per cent: if the transfer if made to brothers and sisters; in this case, the transfer is subject to the tax on the value exceeding euro 100,000 (per beneficiary);
(c) 6 per cent: if the transfer is made to relatives up to the fourth degree, to persons related by direct affinity as well as to persons related by collateral affinity up to the third degree; and
(d) 8 per cent: in all other cases.

If the transfer is made in favor of persons with severe disabilities, the tax applies on the value exceeding euro 1,500,000. Moreover, an anti-avoidance rule is provided for by Law No. 383 of October 18, 2001 for any gift of assets (including shares) which, if sold for consideration, would give rise to capital gains subject to a substitute tax (*imposta sostitutiva*) provided for by Decree No. 461 of November 21, 1997. In particular, if the donee sells the shares for consideration within five years from the receipt thereof as a gift, the donee is required to pay a relevant substitute tax on capital gains as if the gift had never taken place.

United States taxation

The following is a summary of certain U.S. federal income tax consequences to U.S. Holders (as defined below) of the ownership and disposition of Shares or ADSs. This summary is addressed to U.S. Holders that hold Shares or ADSs as capital assets, and does not purport to address all material tax consequences of the ownership of Shares or ADSs. The summary does not address special classes of investors, such as tax-exempt entities, dealers in securities, traders in securities that elect to mark-to-market, certain insurance companies, broker-dealers, investors liable for alternative minimum tax, investors that actually or constructively own 10% or more of Eni SpA s Shares, a person that purchases or sells Shares or ADSs as part of a wash sale for U.S. federal income tax purposes, investors that hold Shares or ADSs as part of a straddle or a hedging or conversion transaction and investors whose "functional currency" is not the U.S. dollar.

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This summary is based on the tax laws of the United States (including the Internal Revenue Code of 1986, as amended, (the "Code"), its legislative history, existing and proposed regulations thereunder, published rulings and court decisions) as in effect on the date hereof, and which are subject to change (or changes in interpretation), possibly with retroactive effect. The summary is based in part on representations of the Depositary and assumes that each obligation in the Deposit Agreement and any related agreement will be performed in accordance with its terms. U.S. Holders should consult their own tax advisors to determine the U.S. federal, state and local and foreign tax consequences to them of the ownership and disposition of Shares or ADSs.

If a partnership holds the Shares or ADSs, the U.S. federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership. A partner in a partnership holding the Shares or ADSs should consult its tax advisor with regard to the U.S. federal income tax treatment of an investment in the Shares or ADSs.

As used in this section, the term "U.S. Holder" means a beneficial owner of Shares or ADSs that is: (i) a citizen or resident of the United States; (ii) a domestic corporation; (iii) an estate the income of which is subject to the U.S. federal income tax without regard to its source; or (iv) a trust if a court within the United States is able to exercise primary supervision over the administration of the trust and one or more U.S. persons have the authority to control all substantial decisions of the trust.

The discussion does not address any aspects of U.S. taxation other than U.S. federal income taxation. In particular, U.S. Holders are urged to confirm their eligibility for benefits under the income tax convention between the United States and Italy with their advisors and to discuss with their advisors any possible consequences of their failure to qualify for such benefits.

In general, and taking into account the earlier assumptions, for U.S. federal income tax purposes, U.S. Holders who own ADRs evidencing ADSs will be treated as owners of the underlying Shares. Exchanges of Shares for ADRs and ADRs for Shares generally will not be subject to U.S. federal income tax.

Dividends

Subject to the passive foreign investment company (PFIC), rules discussed below, distributions paid on the shares will generally be treated as dividends for U.S. federal income tax purposes to the extent paid out of Eni SpA s current or accumulated earnings and profits as determined for U.S. federal income tax purposes, but will not be eligible for the dividends-received deduction generally allowed to U.S. corporations. To the extent that a distribution exceeds Eni SpA s earnings and profits, it will be treated, first, as a non-taxable return of capital to the extent of the U.S. Holder s tax basis in the Shares or ADSs, and thereafter as capital gain. A U.S. Holder will be subject to U.S. federal taxation, on the date of actual or constructive receipt by the U.S. Holder (in the case of Shares) or by the Depositary (in the case of ADSs) with respect to the gross amount of any dividends, including any Italian tax withheld therefrom, without regard to whether any portion of such tax may be refunded to the U.S. Holder by the Italian Tax Authorities. For non-corporate U.S. Holders, dividends paid that constitute qualified dividend income will be taxable at the preferential rates applicable to long-term capital gains provided that such person holds the Shares or ADSs for more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meet other holding period requirements. Dividends paid by the Group with respect to the Shares or ADSs will generally be qualified as dividend income. The amount of the dividend distribution that must be included in the income of a U.S. Holder will be the U.S. dollar value of the euro payments made, determined at the spot euro/$ rate on the date the dividend distribution is includible in such person s income, regardless of whether the payment is in fact converted into U.S. dollars. Generally, any gain or loss resulting from currency exchange fluctuations during the period from the date the U.S. Holder includes the dividend payment in income to the date he or she converts the payment into U.S. dollars will be treated as ordinary income or loss and will not be eligible for the special tax rate applicable to qualified dividend income. The gain or loss generally will be income or loss from sources within the United States for foreign tax credit limitation purposes.

Subject to certain conditions and limitations, Italian tax withheld from dividends will be treated as a foreign income tax eligible for credit against the U.S. Holder s U.S. federal income tax liability. Special rules apply in determining the foreign tax credit limitation with respect to dividends that are subject to the preferential rates. To the extent a refund of the tax withheld is available to a U.S. Holder under Italian law or under the income tax convention between the United States and Italy, the amount of tax withheld that is refundable will not be eligible for credit against his or her U.S. federal income tax liability. See "Italian taxation Income tax" above, for the procedures for obtaining a tax refund. For foreign tax credit purposes, dividends paid on the shares will be income from sources outside the United States and will, depending on your circumstances, be either "passive" or "general" income for purposes of computing the foreign tax credit allowable to you.

Sale or exchange of shares

Subject to the PFIC rules discussed below, a U.S. Holder generally will recognize gain or loss for U.S. federal income tax purposes on the sale or exchange of Shares or ADSs equal to the difference between the U.S. Holder s adjusted basis in the Shares or ADSs (determined in U.S. dollars), as the case may be, and the amount realized on the sale or exchange (or if the amount realized is denominated in a foreign currency its U.S. dollar equivalent, determined at the spot rate on the date of disposition). Generally, such gain or loss will be treated as capital gain or loss if the Shares or ADSs are held as capital assets and will be a long-term capital gain or loss if the Shares or ADSs have been held for more than one year on the date of such sale or exchange. Long-term capital gain of a non corporate U.S. Holder is generally taxed at preferential rates. In addition, any such gain or loss realized by a U.S. Holder generally will be treated as U.S. source income or loss for U.S. foreign tax credit purposes.

PFIC rules

Eni SpA believes that Shares and ADSs should not be treated as stock of a PFIC for U.S. federal income tax purposes, but this conclusion is a factual determination that is made annually and thus may be subject to change. If Eni SpA were to be treated as a PFIC, unless a U.S. Holder elects to be taxed annually on a mark-to-market basis with respect to the Shares or ADSs, gain realized on the sale or other disposition of your Shares or ADSs would in general not be treated as capital gain. Instead, if classified as a U.S. Holder, one would be treated as having realized such gains and certain "excess distributions" ratably over the holding period for the Shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain or distribution was allocated, together with an interest charge in respect of the tax attributable to each such year. With certain exceptions, a U.S. Holder s Shares or ADSs will be treated as stock in a PFIC if Eni SpA were a PFIC at any time during the period the Shares or ADSs were held. Dividends received from Eni SpA will not be eligible for the preferential tax rates applicable to qualified dividend income if Eni SpA is treated as a PFIC with respect to the U.S. Holders either in the taxable year of the distribution or the preceding taxable year, but instead will be taxable at rates applicable to ordinary income.

Documents on display

Eni s Annual Report and Accounts and any other document concerning the Company are also available online on the Company website at:

http://www.eni.com/en_IT/documentation/documentation.page?type=bilrap&header=documentazione&doc_from=hpeni_head

The Company is subject to the information requirements of the U.S. Security Exchange Act of 1934 applicable to foreign private issuers.

In accordance with these requirements, Eni files its annual report on Form 20-F and other related documents with the U.S. SEC. It s possible to read and copy documents that have been filed with the U.S. SEC at the U.S. SEC s public reference room located at 100 F Street NE, Washington, DC 20549, USA.

You may also call the U.S. SEC at +1 800-SEC-0330 or log on to www.sec.gov.

It is also possible to read and copy documents referred to in this annual report on Form 20-F at the New York Stock Exchange, 20 Broad Street, 17th floor, New York, USA.

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Item 11. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the possibility that the exposure to fluctuations in currency exchange rates, interest rates or commodity prices will adversely affect the value of the Group s financial assets, liabilities or expected future cash flows. Eni s financial performance is particularly sensitive to changes in the price of crude oil and movements in the euro/$ exchange rate. Overall, a rise in the price of crude oil has a positive effect on Eni s results from operations and liquidity due to increased revenues from oil and gas production. Conversely, a decline in crude oil prices reduces Eni s results from operations and liquidity.

The impact of changes in crude oil prices on the Company s downstream gas and refining and marketing businesses and petrochemical operations depends upon the speed at which the prices of finished products adjust to reflect changes in crude oil prices. In addition, the Group s activities are, to various degrees, sensitive to fluctuations in the euro/$ exchange rate as commodities are generally priced internationally in U.S. dollars or linked to dollar denominated products as in the case of gas prices. Overall, an appreciation of the euro against the dollar reduces the Group s results from operations and liquidity, and vice versa.

As part of its financing and cash management activities, the Company uses derivative instruments to manage its exposure to changes in interest rates and foreign exchange rates. These instruments are principally interest rate and currency swaps. The Company also enters into commodity derivatives as part of its ordinary commercial, optimization and risk management activities, as well as exceptionally to hedge the exposure to variability in future cash flows due to movements in commodity prices, in view of pursuing acquisitions of oil and gas reserves as part of the Company s ordinary asset portfolio management or other strategic initiatives.

The Company actively manages market risk in accordance with a set of policies and guidelines that provide a centralized model of undertaking finance, treasury and risk management operations based on the Company s departments of operational finance: the parent company s (Eni SpA) finance department and its subsidiaries Eni Finance International, Eni Finance USA and Banque Eni, which is subject to certain bank regulatory restrictions preventing the Group s exposure to concentrations of credit risk, and Eni Trading & Shipping, that is in charge to execute certain activities relating to commodity derivatives. In particular, Eni SpA and Eni Finance International manage subsidiaries financing requirements in and outside Italy, respectively, covering funding requirements and using available surpluses. All transactions concerning currencies and derivative contracts on interest rates and currencies are managed by the parent company. The commodity risk of each business unit (Eni s Divisions or subsidiaries) is pooled and managed by the parent company Midstream business department, with Eni Trading & Shipping executing the negotiation of commodity derivatives.

During 2013, the above mentioned centralized model for the execution of financial derivatives has been ring-fenced in light of the relevant new financial regulations which became effective (EMIR/Dodd Frank). Eni s activities are now in compliance with regulatory requirements which mandate that derivatives instruments be executed on an European Regulated Market or non European exchange, on a Multilateral Trading Facilities or purely OTC, by using semi-automated broker/crossing platform (so-called OTF) or directly with a counterpart.

In addition to the reinforcement of the centralized execution model, as required by the new financial regulation, in 2013 the EMIR concepts of "risk reducing" and "non-risk reducing" derivatives were introduced. Activities in financial derivatives were thus classified in order to clearly: (a) isolate ex ante non-risk reducing activities; (b) define a priori the types of OTC derivative contracts included in the hedging portfolios and the eligibility criteria, and stating that the transactions in contracts included in the hedging portfolios are limited to covering risks directly related to commercial or treasury financing activities; and (c) provide for a sufficiently disaggregate view of the hedging portfolios in terms of for example asset class, product and time horizon, in order to establish the direct link between the portfolio of hedging transactions and the risks that this portfolio seeks to hedge. A derivative can be qualified a risk reducing instrument when, by itself or in combination with other derivative contracts (so-called macro or portfolio hedging) it: i) directly or through closely correlated instruments (so-called proxy hedging) covers the risks arising from potential changes in value, direct or caused by fluctuation of interest rates, inflation rates, foreign exchange rates or credit risk, of different assets under Eni control or that Eni will have under its control in the normal course of business or; ii) qualifies as a hedging contract pursuant to IFRS.

Use of financial derivatives (in euro or currencies different from euro) is allowed with the following risk reducing purposes:

Back to back: includes market risk-free instruments that are negotiated in accordance to an execution criteria and normally settled with an intermediation fee. They normally comply with hedge accounting requirements or own use exemption. These are transaction-based activities characterized by a substantial absence of market risk. A hedging instrument can be considered back to back when the financial derivative is structured as to match as much as possible asset class, size and maturity of the hedged position. As a result the combination of the hedged item, normally a single asset/contract or an order received by mean of an internal derivative, and the hedging instrument, i.e. the financial derivative, is substantially market risk free or is exposed only to a basic risk related to the ineffective portion of the hedging item. In addition, the hedging item may entail counterparty risk and operational risk. These derivatives are normally accounted for as hedges for financial statement purposes.

Flow hedging: flow hedging seeks to optimize Group hedging requirements by pooling different positions retained by the business units and then by entering derivative instruments to hedge net exposures, in accordance to a portfolio basis. A central department processes a continuous flow of orders from the Group various business units and then acts as a single broker on financial markets. Flow hedging is characterized by the lack of direct control by the central broker entity on the received orders, which are normally related to assets managed by the business units. The central broker entity can normally rely on a continuous flow of hedging orders that can be predictable to a large extent, on the basis of the regular hedging programs made by the Group s business units. The central entity is therefore in the position to net opposite orders, by retaining the level of risk necessary to cover timing, volume and asset class mismatch among orders. The benefits are the maximization of integration across the whole of the Group assets portfolio and the related netting potential, avoiding unnecessary derivatives, thus reducing costs and aggregated notional amounts of hedging programs. Flow hedging is managed on a portfolio basis and is dynamic by nature, since resulting net position is normally adjusted in order to take into account new orders received and maximum allowed exposure, related to timing, volume and asset classes mismatch. Those derivatives are accounted to profit and loss as the hedging of net exposures does not qualify as hedges under IFRS.

Asset-backed hedging: is a portfolio-based activity performed to protect assets extrinsic value which is the fair value that a third party would potentially pay to buy the flexibility associated to assets available to the Group. It is normally characterized by a maximum level of market risk related to the size of managed assets and the volatility of underlying commodities. The more flexible is an asset the higher is its extrinsic value that can be normally quantified as an option premium, linked to the price of an underlying commodity, volatility, time, interest rate. In order to protect the value of asset flexibility a business unit may transfer to a central entity part or the whole of asset flexibility or a portfolio of flexibilities and the central entity will hedge such flexibility on financial markets so to lock its value by monetizing it via derivatives. Hedging strategies adopted for asset-backed hedging are normally portfolio based, very dynamic and entail large use of proxies. Depending on the optimization model such strategies are continuously adjusting relevant hedging ratios buying and selling same financial products several times, since the underlying asset flexibility to be hedged is changing depending on price level, price volatility, time to delivery, etc. These derivatives may lead to gains as well as losses which in each case may be significant are accounted through profit and loss as they lack the hedge requirements provided by IFRS. However, we believe that the risks associated with those derivatives are mitigated by the natural hedge granted by the asset availability.

Portfolio management: is a portfolio based activity performed on a combination of underlying positions, such as physical assets (production plants, transmission infrastructures, storages, etc.), commercial assets (spot and forward short/medium/long term supply and sale contracts with physical delivery) and related financial derivatives. Normally the target of a portfolio management activity is to optimize managed assets base by running quantitative models which, given production/consumption forecasts, prices scenarios and logistic flexibility/constraints, determine the optimal configuration in term of volume, price and flexibility for physical and commercial assets in the portfolio. Financial derivatives are then used in the portfolio management activity in order to manage the overall risk level associated to such optimal configuration within a set tolerance or to balance the combined risk-reward profile of the portfolio in line with company s targets. Market risk associated to portfolio management is proportional to assets size and maturity and volatility/correlation of underlying markets. Financial derivatives are normally used to hedge the resulting net position, but they might hedge also single physical/commercial assets included in the portfolio. The activity is dynamic by nature, since optimization models are run periodically, even on a daily and infra-daily timescale, in order to rebalance optimal configuration in view of actual or forecast changes in volumes, prices and flexibility. As a consequence financial Derivatives are also managed dynamically, with a continuous adjustment that might lead to buy and sell the same financial product several times. These derivatives may lead to gains as well as losses which in each case may be significant and are accounted through profit as they lack the hedge requirements provided by IFRS.

Pursuant to internal policy, all derivatives transactions concerning interest rates and foreign currencies are executed for risk reducing purposes, as described above. Only commodity derivatives can also be executed in the context of non-risk reducing operations and be consequently classified as Proprietary Trading, which is an ancillary activity not related to industrial assets that makes use of financial derivatives which are entered into with the objective to obtain an uncertain profit, if favorable market expectations occur.

Eni monitors on a daily basis that every activity involving derivatives is correctly classified according to the risk reducing taxonomy (i.e. back to back, flow hedging, asset-backed hedging or portfolio management), is directly or indirectly related to the hedged industrial assets and effectively optimizes the risk profile to which Eni is, or could be, exposed. When some derivatives fail to prove their risk reducing purpose, they are reclassified as Proprietary Trading. Provided that Proprietary Trading is segregated ex ante from other activities, its resulting market risk exposure is subject to specific limits expressed in terms of Stop Loss, VaR and notional. The aggregated notional amounts of non-risk reducing derivatives at Group level are constantly benchmarked with the thresholds required by relevant international financial regulations.

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Please refer to "Item 18 note 35 of the Notes to the Consolidated Financial Statements" for a qualitative and quantitative discussion of the Company s exposure to market risks. Please also refer to "Item 18 notes 14, 21, 26 and 31 of the Notes to the Consolidated Financial Statements" for details of the different derivatives owned by the Company in these markets.

Item 12. DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

Item 12A. Debt securities

Not applicable.

Item 12B. Warrants and rights

Not applicable.

Item 12C. Other securities

Not applicable.

Item 12D. American Depositary Shares

In the United States, Eni s securities are traded in the form of American Depositary Shares (ADSs) which are listed on the NYSE. ADSs are evidenced by American Depositary Receipts (ADRs), and each ADR represents two Eni ordinary shares. Since January 18, 2012, Eni s ADRs are issued, cancelled and exchanged at the office of Bank of New York Mellon, as depositary (the "Depositary") under the Deposit Agreement between Eni, the Depositary and the holders of ADRs.

Computershare is the transfer agent for the Eni SpA ADR program.

Société Générale Securities Services SpA and UniCredit SpA are the custodians (the "Custodian") on behalf of the holders of Eni s ADRs, and their principal offices are located in Milan, Italy.

Fees and charges paid by ADR holders
The Depositary collects fees for delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal or from intermediaries acting on their behalf. The Depositary collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of distributable property to pay the fees.

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The table below sets forth all fees and charges that a holder of Eni s ADRs may have to pay, either directly or indirectly, to Bank of New York Mellon, as Depositary.

Type of service	Amount of fees or charges (1)	Depositary Actions
(a) Depositing or substituting the underlying shares	$5.00 (or less) for each 100 ADSs (or portion of 100 ADSs)	Each person to whom ADRs are issued against deposits of shares, including deposits and issuances in respect of: Share distributions, stock split, rights, merger. Exchange of securities or any other transaction or event or other distribution affecting the ADSs or the Deposited Securities.
(b) Selling or exercising rights	$5.00 (or less) for each 100 ADSs (or portion of 100 ADSs)	Distribution or sale of securities, the fee being in an amount equal to the fee for the execution and delivery of ADSs which would have been charged as a result of the deposit of such securities.
(c) Withdrawing an underlying security	$5.00 (or less) for each 100 ADSs (or portion of 100 ADSs)	Acceptance of ADRs surrendered for withdrawal of deposited securities.
(d) Transferring, splitting or grouping receipts	Registration or transfer fees	Transfers, combining or grouping of depositary receipts.
(e) Expenses of the depositary	Varied charges	Expenses incurred on behalf of holders in connection with: The depositary s or its custodian s compliance with applicable law, rule or regulation. Stock transfer or other taxes and other governmental charges. Cable, telex, facsimile transmission/delivery. Expenses of the depositary in connection with the conversion of foreign currency into U.S. dollars (which are paid out of such foreign currency). Any other charge payable by Depositary or its agents.
(f) Distribution of cash	$0.02 (or less) per ADS	Any cash distribution to ADS registered holders.
(g) Depositary services	$0.02 (or less) per ADS per calendar year	Depositary services.

(1) All fees and charges are paid by ADR holders to Bank of New York Mellon as Depositary and Transfer agent.

Fees and payments made by the Depositary to the issuer

The Depositary has agreed to reimburse certain company expenses related to the ADR Program and incurred in connection with the program and the listing of Eni s ADSs on the NYSE. These expenses are mainly related to legal and accounting fees incurred in connection with the preparation of regulatory filings and other documentation related to ongoing U.S. SEC compliance, NYSE listing fees, listing and custodian bank fees, advertising, certain investor relationship programs or special investor relations activities.

For the year 2013, as agreed in the Deposit Agreement with the previous depositary bank, JPMorgan Chase Bank of New York, and subsequent amendments, the Depositary will reimburse to Eni up to $1,100,000 in connection with above mentioned expenditures.

Expenses waived or paid directly to third parties by the Depositary

The Depositary reimbursed to the company, or paid amounts on the company s behalf to third parties, or waived its fees and expenses, of $221,857.78 for the year ended December 31, 2013.

Category of expense reimbursed, waived or paid directly to third parties	**Amount reimbursed, waived or paid directly to third parties for the year ended December 31, 2013**
	(US$)
BNY Mellon products and services	120,000.00
BNY Mellon related to servicing registered shareholders	1,679.83
BNY Mellon paid to third-party vendors [(1)]	100,177.95
Total	**221,857.78**

(1) Includes payments for AGM and related ADR Program services.

PART II

Item 13. DEFAULTS, DIVIDEND ARREARAGES AND DELINQUENCIES

None.

Item 14. MATERIAL MODIFICATIONS TO THE RIGHTS OF SECURITY HOLDERS AND USE OF PROCEEDS

None.

Item 15. CONTROLS AND PROCEDURES

Disclosure controls and procedures
In designing and evaluating the Company s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act"), the Company s management, including the Chief Executive Officer and the Chief Financial Officer, recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and the Company s management necessarily was required to apply its judgment in evaluating the cost benefit relationship of possible controls and procedures. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected.

It should be noted that the Company has investments in certain non-consolidated entities. As the Company does not control or manage these entities, its disclosure controls and procedures with respect to such entities are necessarily more limited than those it maintains with respect to its consolidated subsidiaries.

The Company s management, with the participation of the principal executive officer and principal financial officer, has evaluated the effectiveness of the design and operation of its disclosure controls and procedures pursuant to Rule 13a-14(c) under the Exchange Act as of the end of the period covered by this Annual Report on Form 20-F. Based on that evaluation, the principal executive officer and principal financial officer have concluded that these disclosure controls and procedures are effective.

Management s Annual Report on Internal Control over Financial Reporting
The Company s management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rules 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective can only provide reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness

of an internal control system may change over time.

The Internal Control Committee assists the Board of Directors in setting out the main principles for the internal control system so as to appropriately identify and adequately evaluate, manage, and monitor the main risks related to the Company and its subsidiaries, by laying down the compatibility criteria between said risks and sound corporate management. In addition, this Committee assesses, at least annually, the adequacy, effectiveness, and actual operations of the internal control system.

The Company s management, including the Chief Executive Officer and the Chief Financial Officer, conducted an evaluation of the effectiveness of its internal control over financial reporting based on the Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in 1992. Based on the results of this evaluation, the Group s management concluded that its internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of the Company s internal control over financial reporting as of December 31, 2013, has been audited by Reconta Ernst & Young SpA, an independent registered public accounting firm, as stated in its report that is included on page F-2 of this Annual Report on Form 20-F.

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Changes in Internal Control over Financial Reporting

There have not been changes in the Company s internal control over financial reporting that occurred during the period covered by this Form 20-F that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Item 16A. Board of Statutory Auditors financial expert

Eni s Board of Statutory Auditors has determined that the five members of Eni s Board of Statutory Auditors are "audit committee financial expert": Ugo Marinelli, who is the Chairman of the Board, Francesco Bilotti, the Alternate Auditor drawn from the list of candidates presented by the Shareholder Ministry of the economy and finance who replaced Roberto Ferranti on September 2013, Paolo Fumagalli, Renato Righetti and Giorgio Silva. All members are independent.

Item 16B. Code of Ethics

Eni adopted a Code of Ethics that applies to all Eni s employees including Eni s principal executive officer, principal financial officer and principal accounting officer. Eni published its Code of Ethics on Eni s website. It is accessible at www.eni.com, under the section Corporate Governance. A copy of this Code of Ethics is included as an exhibit to this Annual Report on Form 20-F.

Eni s Code of Ethics contains ethical guidelines, describes corporate values and requires standards of business conduct and moral integrity. The ethical guidelines are designed to deter wrongdoing and to promote honest and ethical conduct, compliance with applicable laws and regulations and internal reporting of violations of the guidelines. The code affirms the principles of accounting transparency and internal control and endorses human rights and the issue of the sustainability of the business model.

Item 16C. Principal accountant fees and services

Reconta Ernst & Young SpA has served as Eni principal independent public auditor for fiscal years 2013 and 2012 for which audited Consolidated Financial Statements appear in this Annual Report on Form 20-F.

The following table shows total fees paid by Eni, its consolidated and non-consolidated subsidiaries and Eni s share of fees incurred by joint ventures for services provided by Eni to its public auditors Reconta Ernst & Young SpA and its respective member firms, for the years ended December 31, 2013 and 2012, respectively:

	Year ended December 31,	
	2012	**2013**

	(euro thousand)	
Audit fees	23,042	28,023
Audit-related fees	1,351	1,574
Tax fees	25	21
All other fees	3	-
Total	**24,421**	**29,618**

Audit fees include professional services rendered by the principal accountant for the audit of the registrant s annual financial statements or services that are normally provided by the accountant in connection with statutory and regulatory filings or engagements, including the audit on the Company s internal control over financial reporting.

Audit-related fees include assurance and related services by the principal accountant that are reasonably related to the performance of the audit or review of the registrant s financial statements and are not reported as Audit fees in this Item. The fees disclosed in this category mainly include audits of pension and benefit plans, merger and acquisition due diligence, audit and consultancy services rendered in connection with acquisition deals, certification services not provided for by law and regulations and consultations concerning financial accounting and reporting standards.

Tax fees include professional services rendered by the principal accountant for tax compliance, tax advice, and tax planning. The fees disclosed in this category mainly include fees billed for the assistance with compliance and reporting of income and value-added taxes, assistance with assessment of new or changing tax regimes, tax consultancy in connection with merger and acquisition deals, services rendered in connection with tax refunds, assistance rendered on occasion of tax inspections and in connection with tax claims and recourses and assistance with assessing relevant rules, regulations and facts going into Eni correspondence with tax authorities.

All other fees include products and services provided by the principal accountant, other than the services reported in Audit fees, Audit-related fees and Tax fees of this Item and consists primarily of fees billed for consultancy services related to IT and secretarial services that are permissible under applicable rules and regulations.

Pre-approval policies and procedures of the Internal Control Committee

The Board of Statutory Auditors has adopted a pre-approval policy for audit and non-audit services that set forth the procedures and the conditions pursuant to which services proposed to be performed by the principal auditors may be pre-approved. Such policy is applied to entities within the Eni Group which are either controlled or jointly controlled (directly or indirectly) by Eni SpA. According to this policy, permissible services within the other audit services category are pre-approved by the Board of Statutory Auditors. The Board of Statutory Auditors approval is required on a case-by-case basis for those requests regarding: (i) audit-related services; and (ii) non-audit services to be performed by the external auditors which are permissible under applicable rules and regulations. In such cases, the Company s internal audit department is charged with performing an initial assessment of each request to be submitted to the Board of Statutory Auditors for approval. The internal audit department periodically reports to Eni s Board of Statutory Auditors on the status of both pre-approved services and services approved on a case-by-case basis rendered by the external auditors.

During 2013, no audit-related fees, tax fees or other non-audit fees were approved by the Board of Statutory Auditors pursuant to the de minimis exception to the pre-approval requirement provided by paragraph (c)(7)(i) (c) of Rule 2-01 of Regulation S-X.

Item 16D. Exemptions from the Listing Standards for Audit Committees

Making use of the exemption provided by Rule 10A-3(c)(3) for non-U.S. private issuers, Eni has identified the Board of Statutory Auditors as the body that, starting from June 1, 2005, performs the functions required by the U.S. SEC rules and the Sarbanes-Oxley Act to be carried out by the audit committees of non-U.S. companies listed on the NYSE (see "Item 6 Board of Statutory Auditors" above).

Item 16E. Purchases of equity securities by the issuer and affiliated purchasers

On May 10, 2013, the Ordinary Shareholders meeting revoked, for the part that had not been accomplished by the date of the meeting, the authorization to purchase ordinary Eni shares, resolved on July 16, 2012 by the Board of Directors. Besides that, the Ordinary Shareholders meeting resolved to authorize the Board of Directors to purchase Eni s shares on the MTA in one or more transactions and in any case within 18 months from the date of the resolution up to a maximum number of 363,000,000 ordinary Eni s shares, for a total amount not less than euro 1.102 and not more than the official price reported by Borsa Italiana for the shares on the trading day prior to each individual transaction, increased by 5%, and in any case up to a total amount of euro 6,000 million, according to the operational procedures established by the rules that govern the organization and management of Borsa Italiana.

As of December 31, 2013, Eni s treasury shares amounted to No. 11,388,287, corresponding to 0.31% of share capital of Eni, represented by No. 3,634,185,330 ordinary shares, for a total book value of euro 201 million. Compared to December 31, 2012, there was no variation regarding the number of Eni s treasury shares.

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Period	Numbers of shares (million)	Average price (euro per share)	Total cost (euro million)	Share capital (%)
2014 (since January 6)	8.85	17.14	151.70	0.24
Total purchased as of March 31, 2014	**8.85**	**17.14**	**152**	**0.24**
minus:				
- stock option exercised and shares granted pursuant to stock option and stock grant plans	0			
Total shares held in treasury	**8.85**			**0.24**

Period	Total numbers of shares purchased	Average price paid per share (euro)	Total number of shares purchased, as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs
At January 6, 2014	-		-	363,000,000
January 2014	3,545,000	17.23	3,545,000	359,455,000
February 2014	3,075,916	16.93	6,620,916	356,379,084
March 2014	2,229,084	17.30	8,850,000	354,150,000
March 2014 (through March 31, 2014)			**8,850,000**	**354,150,000**

Item 16F. Change in Registrant s Certifying Accountant

Not applicable.

Item 16G. Significant differences in Corporate Governance practices as per Section 303A.11 of the New York Stock Exchange Listed Company Manual

Corporate Governance. Eni s governance structure follows the traditional model as defined by the Italian Civil Code which provides for two main separate corporate bodies, the Board of Directors and the Board of Statutory Auditors to whom management and monitoring duties are respectively entrusted.

This model differs from the U.S. one-tier model in which the Board of Directors is the sole corporate body responsible for management, with an Audit Committee established within the Board performing monitoring activities.

The following offers a description of the most significant differences between corporate governance practices adopted by U.S. domestic companies under the NYSE standards and those followed by Eni, also with reference to Corporate

Governance Code for listed companies, which Eni has adopted (hereinafter the Corporate Governance Code).

Independent Directors

NYSE standards. In accordance with NYSE standards, the majority of the members on the Boards of Directors of U.S. companies must be independent. A Director qualifies as independent when the Board affirmatively determines that such Director does not have a material relationship with the listed company (and its subsidiaries), either directly, or indirectly. In particular, a Director may not be deemed independent if he or she or an immediate family member has a certain specific relationship with the issuer, its auditors or companies that have material business relationships with the issuer (e.g. he or she is an employee of the issuer or a partner of the auditor).

In addition, a Director cannot be considered independent in the three-year "cooling-off" period following the termination of any relationship that compromised a Director s independence.

Eni standards. In Italy, the Consolidated Law on Financial Intermediation states that at least one of the Directors or two, if the Board is composed of more than seven members, must meet the independence requirements for Statutory Auditors of listed companies.

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In particular, a Director may not be deemed independent if he/she or an immediate family member has relationships with the issuer, with its Directors or with the companies in the same group of the issuer that could influence the independence of their judgment.

Eni s By-laws require that at least one Director if the Board has no more than five members or at least three Directors if the Board is composed of more than five members must satisfy the independence requirements.

The Corporate Governance Code provides for additional independence requirements, recommending that the Board of Directors includes an adequate number of independent non-executive Directors. In particular, for issuers belonging to FTSE-Mib index of the Italian Stock Market, like Eni, the Corporate Governance Code recommends that at least one third of the members of the Board of Directors shall be independent Directors. In any event, independent Directors shall not be fewer than two. Independence is defined as not being currently or recently involved in any direct or indirect relationship with the issuer or other parties associated with the issuer and which may influence his/her independent judgment.

After the appointment of a Director who qualifies him or herself as independent and subsequently, upon the occurrence of circumstances affecting the independence requirements and in any case at least once a year, the Board of Directors assesses the independence of the Director. The Board of Statutory Auditors verifies the correct application of the criteria and procedures adopted by the Board of Directors to evaluate the independence of its members.

The Board of Directors shall disclose the result of its evaluations, after the appointment, through a press release to the market and, subsequently, in the Annual Corporate Governance Report.

In accordance with Eni s By-laws, if a Director does not or no longer satisfies the independence requirements or the minimum number of independent Directors fall below the threshold set by Eni s By-laws, the Board declares the Director disqualified and provides for their substitution. Directors shall notify the Company if they should no longer satisfy the independence and integrity requirements or if cause for ineligibility or incompatibility should arise.

Meetings of non-executive Directors

NYSE standards. Non-executive Directors, including those who are not independent, must meet on a regular basis without the executive Directors.

In addition, if the group of non-executive Directors includes Directors who are not independent, independent Directors should meet separately at least once a year.

Eni standards. Pursuant to Corporate Governance Code, independent Directors shall meet at least once a year without the other Directors. During 2013, Eni s independent Directors had numerous opportunities to meet, formally and informally, to hold discussions and exchange opinions.

Audit Committee

NYSE standards. Listed U.S. companies must have an Audit Committee that satisfies the requirements of Rule 10A-3 under the Securities Exchange Act of 1934 and that complies with the provisions of the Sarbanes-Oxley Act and of

Section 303A.07 of the NYSE Listed Company Manual.

Eni standards. At its Meeting of March 22, 2005, the Board of Directors, as permitted by the rules of the U.S. Securities and Exchange Commission applicable to foreign issuers listed on regulated U.S. markets, assigned to the Board of Statutory Auditors, effective from June 1, 2005 and within the limits set by Italian law, the functions specified and the responsibilities assigned to the Audit Committee of such foreign issuers by the Sarbanes-Oxley Act and the U.S. SEC rules (see "Item 6   Board of Statutory Auditors" earlier).

Under Section 303A.07 of the NYSE Listed Company Manual, audit committees of U.S. companies have additional functions and duties which are not mandatory for non-U.S. private issuers and which are therefore not included in the list of functions reported in "Item 6   Board of Statutory Auditors".

Nominating/Corporate Governance Committee

NYSE standards. U.S. listed companies must have a Nominating/Corporate Governance Committee (or equivalent body) composed entirely of independent Directors whose functions include, but are not limited to, selecting qualified

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candidates for the office of Director for submission to the Shareholders Meeting, as well as developing and recommending corporate governance guidelines to the Board of Directors. This provision is not binding for non-U.S. private issuers.

Eni standards. Pursuant to the Corporate Governance Code, the Board of Directors shall establish among its members a nomination committee the majority of whose member shall be independent Directors.

On July 28, 2011, the Board of Directors of Eni established the Nomination Committee, chaired by the Chairman of the Board of Directors, Giuseppe Recchi, and composed of the Chairmen of the other Board Committees: Alessandro Lorenzi (Chairman of the Control and Risk Committee), Alessandro Profumo (Chairman of the Oil-Gas Energy Committee) and Mario Resca (Chairman of the Compensation Committee). The Nomination Committee is made up of three to four Directors, a majority of whom are independent in accordance with the recommendations of the Corporate Governance Code[29]. Further details on this Committee are reported in the Item 6.

Compensation Committee

NYSE standards. U.S. listed companies must have a Compensation Committee composed entirely of independent Directors who must satisfy the independence requirements provided for its members. The Compensation Committee must have a written charter that addresses the Committee s purpose and responsibilities within the limit set forth by the listing rules. The Compensation Committee may, in its sole discretion, retain or obtain the advice of a compensation consultant, independent legal counsel or other adviser and shall be directly responsible for the appointment, compensation and oversight of the work of any compensation consultant, independent legal counsel or other adviser retained by it. These provisions are not binding for non-U.S. private issuers.

Eni standards. Pursuant to the Corporate Governance Code, the Board of Directors shall establish among its members a Compensation Committee made up of four non-executive Directors, all of whom shall be independent or, alternatively, a majority of whom shall be independent. In the latter case, the Chairman of the Committee shall be chosen from among the independent Directors. At least one of the Committee s members shall have an adequate understanding of and experience in financial matters or compensation policies.

First established by the Board of Directors in 1996, the Compensation Committee is currently chaired by Director Mario Resca. The other members include directors Carlo Cesare Gatto, Roberto Petri and Alessandro Profumo. Further details on this Committee are reported in the Item 6.

Code of Business Conduct and Ethics

NYSE standards. he NYSE listing standards require each U.S. listed company to adopt a Code of Business Conduct and Ethics for its directors, officers and employees, and to promptly disclose any waivers of the code for directors or executive officers.

Eni standards. At its meetings of December 15, 2003, and January 28, 2004, the Board of Directors of Eni approved an organizational, management and control model pursuant to Italian Legislative Decree No. 231 of 2001 (hereinafter "Model 231") and established the associated Eni Watch Structure. Moreover, after subsequent approvals of the updates to Model 231 in response to changes in the Italian legislation governing the matter and in the Company organizational structures, on March 14, 2008, the Board of Directors approved the overall revision of Model 231 and adopted Eni s Code of Ethics replacing the previous version of Eni s Code of Conduct of 1998. Eni s Code of Ethics, which is an integral part of Model 231, sets out a clear definition of the value system that Eni recognizes, accepts and upholds and the responsibilities that Eni assumes internally and externally in order to ensure that all its business activities are conducted in compliance with the law, in a context of fair competition, with honesty, integrity, correctness and in good faith, respecting the legitimate interests of all the stakeholders with whom Eni interacts on an ongoing basis. These include shareholders, employees, suppliers, customers, commercial and financial partners, and the local communities and institutions of the countries where Eni operates. All Eni personnel, without exception or distinction, starting with Directors, senior management and members of the Company s bodies, as also required under U.S. SEC rules and the Sarbanes-Oxley Act, are committed to observing and enforcing the principles set out in the Code of Ethics in the performance of their functions and duties. The synergies between the Code of Ethics and Model 231 are underscored by the designation of the Eni Watch Structure, established under Model 231, as the Guarantor of the Code of Ethics. The Guarantor of the Code of Ethics acts to ensure the protection and promotion of the above principles. Every six months, it presents a report on the implementation of the Code to the Control and Risk Committee, to the Board of Statutory Auditors and to the Chairman and the CEO, who in turn reports on this to the Board of Directors. The composition of the Model 231 Watch Structure initially formed of only three members was modified in 2007

(29) The Committee is currently made up of four Directors, three of whom are independent. The Chairman is not independent pursuant to the Corporate Governance Code which provides that the Chairman of the Board of Directors shall not be considered independent being a "significant representative" of the Company.

with the inclusion of two external members, one of whom was appointed the Chairman of the Watch Structure itself, selected from among academics and professionals with proven experience in economic and business management matters. The internal members are the Senior Executive Vice President Legal Affairs, Executive Vice President Human Resources and Organization and Senior Executive Vice President Internal Audit of the Company. On May 19, 2011, the Board of Directors, with the favorable opinion of the Board of Statutory Auditors, appointed the current members of the Watch Structure.

Item 16H. Mine safety disclosure

Not applicable since Eni does not engage in mining operations.

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PART III

Item 17. FINANCIAL STATEMENTS

Not applicable.

Item 18. FINANCIAL STATEMENTS

Index to Financial Statements:

Item 19. EXHIBITS

1. By-laws of Eni SpA

8. List of subsidiaries

11. Code of Ethics

Certifications:

12.1. Certification pursuant to Rule 13a-14(a) of the Securities Exchange Act
12.2. Certification pursuant to Rule 13a-14(a) of the Securities Exchange Act

13.1. Certification furnished pursuant to Rule 13a-14(b) of the Securities Exchange Act (such certificate is not deemed filed for purpose of Section 18 of the Exchange Act and not incorporated by reference with any filing under the

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Eni SpA

We have audited the accompanying consolidated balance sheets of Eni SpA as of December 31, 2013 and 2012, and the related consolidated profit and loss account and consolidated statements of comprehensive income, changes in shareholders equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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 Eni SpA at December 31, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

As discussed in Note 4 to the consolidated financial statements, the Company changed the manner in which it accounts interests in joint arrangements in 2013 as a result of adopting new International Financial Reporting Standards.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Eni SpA s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated April 10, 2014 expressed an unqualified opinion thereon.

/s/ Reconta Ernst & Young SpA

Rome, Italy

April 10, 2014

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Eni SpA

We have audited Eni SpA s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission 1992 framework (the COSO criteria). Eni SpA 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 Annual Report on Internal Control over Financial Reporting on page 187. Our responsibility is to express an opinion on the company 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, Eni SpA maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, 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 sheets of Eni SpA as of December 31, 2013 and 2012, and the related consolidated profit and loss account and consolidated statements of comprehensive income, changes in shareholders equity, and cash flows for each of the three years in the period ended December 31, 2013 and our report dated April 10, 2014 expressed an unqualified opinion thereon.

/s/ Reconta Ernst & Young SpA

Rome, Italy

April 10, 2014

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CONSOLIDATED BALANCE SHEET

(euro million)

Jan. 1, 2012 (a)			Dec. 31, 2012 (a)		Dec. 31, 2013	
Total amount		**Note**	**Total amount**	***of which with related parties***	**Total amount**	***of which with related parties***
	ASSETS					
	Current assets					
1,691	Cash and cash equivalents	(7)	7,936		5,431	
	Other financial assets held for trading	(8)			5,004	
266	Other financial assets available for sale	(9)	237		235	
24,626	Trade and other receivables	(10)	28,618	*2,594*	28,890	*1,869*
7,650	Inventories	(11)	8,578		7,939	
549	Current tax assets	(12)	771		802	
1,400	Other current tax assets	(13)	1,239		835	
2,319	Other current assets	(14)	1,617	*8*	1,325	*15*
38,501			**48,996**		**50,461**	
	Non-current assets					
74,981	Property, plant and equipment	(15)	64,798		63,763	
2,435	Inventory - compulsory stock	(16)	2,541		2,573	
10,905	Intangible assets	(17)	4,487		3,876	
5,024	Equity-accounted investments	(18)	3,453		3,153	
399	Other investments	(18)	5,085		3,027	
1,227	Other financial assets	(19)	913	*334*	858	*320*
5,564	Deferred tax assets	(20)	5,005		4,658	
4,225	Other non-current receivables	(21)	4,398	*43*	3,676	*42*
104,760			**90,680**		**85,584**	
230	**Assets held for sale**	(32)	**516**		**2,296**	
143,491	**TOTAL ASSETS**		**140,192**		**138,341**	
	LIABILITIES AND SHAREHOLDERS EQUITY					
	Current liabilities					
4,241	Short-term debt	(22)	2,032	*154*	2,553	*264*
2,190	Current portion of long-term debt	(27)	3,015		2,132	
22,971	Trade and other payables	(23)	23,666	*1,583*	23,701	*2,160*
2,109	Income taxes payable	(24)	1,633		755	
1,924	Other taxes payable	(25)	2,188		2,291	
2,242	Other current liabilities	(26)	1,418	*6*	1,437	*17*
35,677			**33,952**		**32,869**	
	Non-current liabilities					
23,024	Long-term debt	(27)	19,145		20,875	
12,708	Provisions for contingencies	(28)	13,567		13,120	
1,288	Provisions for employee benefits	(29)	1,407		1,279	
7,125	Deferred tax liabilities	(30)	6,745		6,750	
3,464	Other non-current liabilities	(31)	2,598	*16*	2,259	
47,609			**43,462**		**44,283**	
24	**Liabilities directly associated with assets held for sale**	(32)	**361**		**140**	
83,310	**TOTAL LIABILITIES**		**77,775**		**77,292**	

	SHAREHOLDERS EQUITY	(33)		
4,761	**Non-controlling interest**		**3,357**	**2,839**
	Eni shareholders equity			
4,005	Share capital		4,005	4,005
49	Reserve related to cash flow hedging derivatives net of tax effect		(16)	(154)
53,143	Other reserves		49,438	51,393
(6,753)	Treasury shares		(201)	(201)
(1,884)	Interim dividend		(1,956)	(1,993)
6,860	Net profit		7,790	5,160
55,420	**Total Eni shareholders equity**		**59,060**	**58,210**
60,181	**TOTAL SHAREHOLDERS EQUITY**		**62,417**	**61,049**
143,491	**TOTAL LIABILITIES AND SHAREHOLDERS EQUITY**		**140,192**	**138,341**

(a) See note 4 Financial statements and changes in accounting policies for information on the restatement of comparative amounts as a result of the adoption of new IFRS effective from 2013.

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CONSOLIDATED PROFIT AND LOSS ACCOUNT
(euro million except as otherwise stated)

		2011		2012 [(a)]		2013	
	Note	Total amount	*of which with related parties*	Total amount	*of which with related parties*	Total amount	*of which with related parties*
REVENUES							
Net sales from operations	(36)	107,690	*3,477*	127,109	*3,622*	114,697	*3,184*
Other income and revenues		926	*41*	1,548	*57*	1,387	*33*
		108,616		**128,657**		**116,084**	
OPERATING EXPENSES	(37)						
Purchases, services and other		78,795	*5,880*	95,034	*6,093*	90,003	*7,897*
- of which non-recurring charge (income)	(44)	*69*					
Payroll and related costs		4,404	*33*	4,640	*21*	5,301	*41*
OTHER OPERATING (EXPENSE) INCOME	(37)	**171**	*32*	**(158)**	*10*	**(71)**	*68*
DEPRECIATION, DEPLETION, AMORTIZATION AND IMPAIRMENTS	(37)	**8,785**		**13,617**		**11,821**	
OPERATING PROFIT		**16,803**		**15,208**		**8,888**	
FINANCE INCOME (EXPENSE)	(38)						
Finance income		6,376	*49*	7,208	*28*	5,732	*41*
Finance expense		(7,410)	*(1)*	(8,327)	*(2)*	(6,653)	*(85)*
Finance expense from financial instruments held for trading, net						4	
Finance expense from derivative financial instruments, net		(112)		(252)		(92)	
		(1,146)		**(1,371)**		**(1,009)**	
INCOME (EXPENSE) FROM INVESTMENTS	(39)						
Share of profit (loss) of equity-accounted investments		500		186		222	
Other gain (loss) from investments		1,623	*338*	2,603		5,863	
- of which gain on disposals of the 28.57% of Eni East Africa BV						*3,359*	
		2,123		**2,789**		**6,085**	
PROFIT BEFORE INCOME TAXES		**17,780**		**16,626**		**13,964**	
Income taxes	(40)	(9,903)		(11,679)		(9,005)	
Net profit for the year - Continuing operations		**7,877**		**4,947**		**4,959**	
Net profit (loss) for the year - Discontinued operations		**(74)**	*400*	**3,732**	*2,234*		
Net profit for the year - Continuing operations		**7,803**		**8,679**		**4,959**	
Attributable to Eni							
Continuing operations		6,902		4,200		5,160	
Discontinued operations		(42)		3,590			
		6,860		**7,790**		**5,160**	
Attributable to non-controlling interest	(33)						
Continuing operations		975		747		(201)	
Discontinued operations		(32)		142			
		943		**889**		**(201)**	

Earnings per share attributable to Eni (euro per share)	(41)			
Basic		1.89	2.15	1.42
Diluted		1.89	2.15	1.42
Earnings per share attributable to Eni				
- Continuing operations (euro per share)	(41)			
Basic		1.90	1.16	1.42
Diluted		1.90	1.16	1.42

(a) See note 4 Financial statements and changes in accounting policies for information on the restatement of comparative amounts as a result of the adoption of new IFRS effective from 2013.

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CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(euro million)

	Note	2011	2012 [(a)]	2013
Net profit		**7,803**	**8,679**	**4,959**
Other items of comprehensive income				
Items not to be reclassified to profit or loss in subsequent periods				
Revaluations of defined benefit plans	(33)		(151)	65
Share of other comprehensive income on equity-accounted entities in relation to revaluations of defined benefit plans	(33)		2	(3)
Tax effect	(33)		53	(40)
			(96)	**22**
Other comprehensive income to be reclassified to profit or loss in subsequent periods				
Foreign currency translation differences	(33)	1,031	(716)	(1,871)
Change in the fair value of investments	(33)		141	(64)
Change in the fair value of other available-for-sale financial instruments	(33)	(6)	16	(1)
Change in the fair value of cash flow hedging derivatives	(33)	352	(103)	(198)
Share of other comprehensive income on equity-accounted entities	(33)	(13)	8	
Tax effect	(33)	(128)	32	63
		1,236	**(622)**	**(2,071)**
Total other items of comprehensive income		**1,236**	**(718)**	**(2,049)**
Total comprehensive income		**9,039**	**7,961**	**2,910**
Attributable to:				
Eni		8,097	7,096	3,164
Non-controlling interest		942	865	(254)
		9,039	**7,961**	**2,910**

(a) See note 4 Financial statements and changes in accounting policies for information on the restatement of comparative amounts as a result of the adoption of new IFRS effective from 2013.

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CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS EQUITY

(euro million)

		Eni shareholders equity														
	Note	Share capital	Legal reserve of Eni SpA	Reserve for treasury shares	Reserve related to the fair value of cash flow hedging derivatives net of the tax effect	Reserve related to the fair value of available-for-sale financial instruments net of the tax effect	Reserve for defined benefit plans net of tax effect	Other reserves	Cumulative currency translation differences	Treasury shares	Retained earnings					
Balance at December 31, 2010		**4,005**	**959**	**6,756**	**(174)**	**(3)**		**1,518**	**539**	**(6,756)**	**39,855**	**(1,811)**	**6,318**	**51,206**	**4,522**	**55,728**
Net profit of the year													**6,860**	**6,860**	**943**	**7,803**
Other items of comprehensive income																
Other comprehensive income to be reclassified to profit or loss in subsequent periods																
Foreign currency translation differences									1,000		31			1,031		1,031
Change in the fair value of other available-for-sale financial instruments net of tax effect						(5)								(5)		(5)
Change in the fair value of cash flow hedge derivatives net of tax effect					223									223		223
Share of "Other comprehensive income" on equity-accounted entities								(12)						(12)	(1)	(13)
					223	**(5)**		**(12)**	**1,000**		**31**			**1,237**	**(1)**	**1,236**
Total comprehensive income of the year					**223**	**(5)**		**(12)**	**1,000**		**31**		**6,860**	**8,097**	**942**	**9,039**
Transactions with shareholders																
Dividend distribution of Eni SpA (euro 0.50 per share in settlement of 2010 interim dividend of euro 0.50 per share)												1,811	(3,622)	(1,811)		(1,811)
Interim dividend distribution of Eni SpA (euro 0.52 per share)												(1,884)		(1,884)		(1,884)
Dividend distribution of other companies															(571)	(571)
Allocation of 2010 net profit											2,696		(2,696)			
Payments by minority shareholders															26	26
Acquisition of non-controlling interest relating to Altergaz SA and Tigáz Zrt								(94)			(25)			(119)	(7)	(126)
Effect related to the purchase of Italgas SpA by Snam SpA								(5)						(5)	5	
Treasury shares sold following the exercise of stock options exercised by Eni managers				(3)						3	3			3		3
								14			(10)			4	13	17

Treasury shares sold following the exercise of stock options by Saipem and Snam managers														
Non-controlling interest excluded following the sale of Eni Acqua Campania SpA and the divestment of the control stake in the share capital of Petromar Lda													(10)	(10)
			(3)			**(85)**		**3**	**2,664**	**(73)**	**(6,318)**	**(3,812)**	**(544)**	**(4,356)**
Other changes in shareholders equity														
Cost related to stock options									2			2		2
Stock options expired									(7)			(7)		(7)
Other changes									(14)			(14)	1	(13)
									(19)			**(19)**	**1**	**(18)**
Balance at December 31, 2011	**4,005**	**959**	**6,753**	**49**	**(8)**	**1,421**	**1,539**	**(6,753)**	**42,531**	**(1,884)**	**6,860**	**55,472**	**4,921**	**60,393**

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CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS EQUITY *continued*

(euro million)

Eni shareholders equity

	Note	Share capital	Legal reserve of Eni SpA	Reserve for treasury shares	Reserve related to the fair value of cash flow hedging derivatives net of the tax effect	Reserve related to the fair value of available-for-sale financial instruments net of the tax effect	Reserve for defined benefit plans net of tax effect	Other reserves	Cumulative currency translation differences	Treasury shares	Retained earnings				
Balance at December 31, 2011		**4,005**	**959**	**6,753**	**49**	**(8)**		**1,421**	**1,539**	**(6,753)**	**42,531**	**(1,884)**	**6,860**	**55,472**	**4,921**	**60,393**
Changes in accounting principles (IFRS 10 and 11)															(151)	(151)
Changes in accounting principles (IAS 19)											(52)			(52)	(9)	(61)
Balance at January 1, 2012		**4,005**	**959**	**6,753**	**49**	**(8)**		**1,421**	**1,539**	**(6,753)**	**42,479**	**(1,884)**	**6,860**	**55,420**	**4,761**	**60,181**
Net profit of the year													**7,790**	**7,790**	**889**	**8,679**
Other items of comprehensive income																
Items not to be reclassified to profit or loss in subsequent periods																
Revaluations of defined benefit plans net of tax effect	(33)						(88)							(88)	(10)	(98)
Share of "Other comprehensive income" on equity-accounted entities in relation to revaluations of defined benefit plans net of tax effect	(33)														2	2
							(88)							**(88)**	**(8)**	**(96)**
Other comprehensive income to be reclassified to profit or loss in subsequent periods																
Foreign currency translation differences	(33)								(597)		(104)			(701)	(15)	(716)
Change in the fair value of investments net of tax effect	(33)					138								138		138
Change in the fair value of other available-for-sale financial instruments net of tax effect	(33)					14								14		14
Change in the fair value of cash flow hedge derivatives net of tax effect	(33)				(65)									(65)	(1)	(66)
Share of "Other comprehensive income" on equity-accounted entities	(33)							8						8		8
					(65)	**152**		**8**	**(597)**		**(104)**			**(606)**	**(16)**	**(622)**

Total comprehensive income of the year					**(65)**	**152**	**(88)**	**8**	**(597)**		**(104)**		**7,790**	**7,096**	**865**	**7,961**
Transactions with shareholders																
Dividend distribution of Eni SpA (euro 0.52 per share in settlement of 2011 interim dividend of euro 0.52 per share)												1,884	(3,768)	(1,884)		(1,884)
Interim dividend distribution of Eni SpA (euro 0.54 per share)	(33)											(1,956)		(1,956)		(1,956)
Dividend distribution of other companies															(681)	(681)
Allocation of 2011 net profit											3,092		(3,092)			
Effect related to the sale of Snam SpA											371			371	(1,602)	(1,231)
Acquisition of non-controlling interest relating to Altergaz SA and Tigáz Zrt	(33)							(4)						(4)	(3)	(7)
Treasury shares sold following the exercise of stock options exercised by Eni managers	(33)			(1)						1	1			1		1
Treasury shares sold following the exercise of stock options by Saipem managers	(33)							7						7	22	29
				(1)				**3**		**1**	**3,464**	**(72)**	**(6,860)**	**(3,465)**	**(2,264)**	**(5,729)**
Other changes in shareholders equity																
Elimination of treasury shares				(6,551)						6,551						
Reconstitution of the reserve for treasury share				6,000							(6,000)					
Stock options expired											(7)			(7)		(7)
Other changes								(1,140)			1,156			16	(5)	11
				(551)				**(1,140)**		**6,551**	**(4,851)**			**9**	**(5)**	**4**
Balance at December 31, 2012	(33)	**4,005**	**959**	**6,201**	**(16)**	**144**	**(88)**	**292**	**942**	**(201)**	**40,988**	**(1,956)**	**7,790**	**59,060**	**3,357**	**62,417**

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CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS EQUITY *continued*

(euro million)

Eni shareholders equity

	Note	Share capital	Legal reserve of Eni SpA	Reserve for treasury shares	Reserve related to the fair value of cash flow hedging derivatives net of the tax effect	Reserve related to the fair value of available-for-sale financial instruments net of the tax effect	Reserve for defined benefit plans net of tax effect	Other reserves	Cumulative currency translation differences	Treasury shares	Retained earnings					
Balance at December 31, 2012	(33)	**4,005**	**959**	**6,201**	**(16)**	**144**	**(88)**	**292**	**942**	**(201)**	**40,988**	**(1,956)**	**7,790**	**59,060**	**3,357**	**62,417**
Net profit of the year													**5,160**	**5,160**	**(201)**	**4,959**
Other items of comprehensive income																
Items not to be reclassified to profit or loss in subsequent periods																
Revaluations of defined benefit plans net of tax effect	(33)						18							18	7	25
Share of "Other comprehensive income" on equity-accounted entities in relation to revaluations of defined benefit plans net of tax effect	(33)						(1)							(1)	(2)	(3)
							17							**17**	**5**	**22**
Other comprehensive income to be reclassified to profit or loss in subsequent periods																
Foreign currency translation differences	(33)						(1)		(1,640)		(171)			(1,812)	(59)	(1,871)
Change in the fair value of investments net of tax effect	(33)					(62)								(62)		(62)
Change in the fair value of other available-for-sale financial instruments net of tax effect	(33)					(1)								(1)		(1)
Change in the fair value of cash flow hedge derivatives net of tax effect	(33)				(138)									(138)	1	(137)
					(138)	**(63)**	**(1)**		**(1,640)**		**(171)**			**(2,013)**	**(58)**	**(2,071)**
Total comprehensive income of the year					**(138)**	**(63)**	**16**		**(1,640)**		**(171)**		**5,160**	**3,164**	**(254)**	**2,910**
Transactions with shareholders																
Dividend distribution of Eni SpA (euro 0.54 per share in settlement of 2012 interim dividend of euro 0.54 per share)	(33)										(829)	1,956	(3,083)	(1,956)		(1,956)
Interim dividend distribution of Eni SpA (euro 0.55 per share)	(33)											(1,993)		(1,993)		(1,993)
Dividend distribution of other companies															(250)	(250)
Allocation of 2012 net profit											4,707		(4,707)			
Acquisition of non-controlling interest relating to Tigáz Zrt	(33)							4						4	(32)	(28)
	(33)														1	1

Payments and reimbursements by/to minority shareholders																
Treasury shares sold following the exercise of stock options by Saipem managers	(33)														1	1
								4			**3,878**	**(37)**	**(7,790)**	**(3,945)**	**(280)**	**(4,225)**
Other changes in shareholders equity																
Elimination of intercompany profit between companies with different Group interest											(32)			(32)	32	
Stock options expired											(13)			(13)		(13)
Other changes											(24)			(24)	(16)	(40)
											(69)			**(69)**	**16**	**(53)**
Balance at December 31, 2013	(33)	**4,005**	**959**	**6,201**	**(154)**	**81**	**(72)**	**296**	**(698)**	**(201)**	**44,626**	**(1,993)**	**5,160**	**58,210**	**2,839**	**61,049**

CONSOLIDATED STATEMENT OF CASH FLOWS

(euro million)

	Note	2011	2012 [(a)]	2013
Net profit of the year - Continuing operations		7,877	4,947	4,959
Adjustments to reconcile net profit to net cash provided by operating activities				
Depreciation and amortization	(37)	7,755	9,645	9,421
Impairments of tangible and intangible assets, net	(37)	1,030	3,972	2,400
Share of (profit) loss of equity-accounted investments	(39)	(500)	(186)	(222)
Gain on disposal of assets, net		(1,176)	(875)	(3,770)
Dividend income	(39)	(659)	(431)	(400)
Interest income		(99)	(94)	(142)
Interest expense		773	808	711
Income taxes	(40)	9,903	11,679	9,005
Other changes		331	(1,947)	(1,882)
Changes in working capital:				
- inventories		*(1,400)*	*(1,402)*	*350*
- trade receivables		*218*	*(3,161)*	*(1,379)*
- trade payables		*34*	*2,014*	*703*
- provisions for contingencies		*109*	*329*	*59*
- other assets and liabilities		*(657)*	*(1,061)*	*723*
Cash flow from changes in working capital		(1,696)	(3,281)	456
Net change in the provisions for employee benefits		(10)	17	6
Dividends received		955	930	630
Interest received		99	79	97
Interest paid		(927)	(829)	(942)
Income taxes paid, net of tax receivables received		(9,893)	(11,882)	(9,301)
Net cash provided by operating activities - Continuing operations		**13,763**	**12,552**	**11,026**
Net cash provided by operating activities - Discontinued operations		**619**	**15**	
Net cash provided by operating activities		**14,382**	**12,567**	**11,026**
- of which with related parties	(43)	***(639)***	***(1,117)***	***(2,911)***
Investing activities:				
- tangible assets	(15)	*(11,658)*	*(11,267)*	*(10,913)*
- intangible assets	(17)	*(1,780)*	*(2,294)*	*(1,887)*
- consolidated subsidiaries and businesses	(34)	*(115)*	*(178)*	*(25)*
- investments	(18)	*(245)*	*(391)*	*(292)*
- securities		*(62)*	*(17)*	*(5,048)*
- financing receivables		*(715)*	*(1,542)*	*(978)*
- change in payables and receivables in relation to investing activities and capitalized depreciation		*379*	*54*	*50*
Cash flow from investing activities		(14,196)	(15,635)	(19,093)
Disposals:				
- tangible assets		*154*	*1,240*	*514*
- intangible assets		*41*	*61*	*16*
- consolidated subsidiaries and businesses	(34)	*1,006*	*3,521*	*3,401*
- investments		*711*	*1,203*	*2,429*
- securities		*128*	*54*	*36*
- financing receivables		*695*	*1,431*	*1,561*

- change in payables and receivables in relation to disposals		*243*	*(252)*	*155*
Cash flow from disposals		2,978	7,258	8,112
Net cash used in investing activities		**(11,218)**	**(8,377)**	**(10,981)**
- of which with related parties	(43)	***(800)***	***1,485***	***(390)***

(a) See note 4 Financial statements and changes in accounting policies for information on the restatement of comparative amounts as a result of the adoption of new IFRS effective from 2013.

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CONSOLIDATED STATEMENT OF CASH FLOWS *continued*

(euro million)

	Note	2011	2012 [(a)]	2013
Proceeds from long-term debt	(27)	4,474	10,506	5,418
Repayments of long-term debt	(27)	(889)	(3,961)	(4,720)
Increase (decrease) in short-term debt	(22)	(2,481)	(731)	1,017
		1,104	**5,814**	**1,715**
Net capital contributions by non-controlling interest		26		1
Sale of treasury shares		3		
Net acquisition of treasury shares different from Eni SpA		17	29	1
Acquisition of additional interests in consolidated subsidiaries		(126)	604	(28)
Dividends paid to Eni s shareholders		(3,695)	(3,840)	(3,949)
Dividends paid to non-controlling interest		(552)	(536)	(250)
Net cash used in financing activities		**(3,223)**	**2,071**	**(2,510)**
- of which with related parties	(43)	***348***	***(93)***	***119***
Effect of change in consolidation (inclusion/exclusion of significant/insignificant subsidiaries)		(7)	(4)	2
Effect of exchange rate changes on cash and cash equivalents and other changes		17	(12)	(42)
Net cash flow of the year		**(49)**	**6,245**	**(2,505)**
Cash and cash equivalents - beginning of the year	(7)	**1,549**	**1,691**	**7,936**
Cash and cash equivalents - end of the year	(7)	**1,500**	**7,936**	**5,431**

(a) See note 4 Financial statements and changes in accounting policies for information on the restatement of comparative amounts as a result of the adoption of new IFRS effective from 2013.

Notes to the Consolidated Financial Statements

1 Basis of presentation

The Consolidated Financial Statements of Eni Group have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB). Oil and natural gas exploration and production activity is accounted for in conformity with internationally accepted accounting standards. Specifically, this concerns the determination of the amortization expenses using the unit-of-production method and the recognition of the production sharing agreement and buy-back contracts. The Consolidated Financial Statements have been prepared on a historical cost basis, taking into account where appropriate of any value adjustments, except for certain items that under IFRS must be recognized at fair value as described in the summary of significant accounting policies paragraph.

The 2013 Consolidated Financial Statements approved by Eni s Board of Directors on March 17, 2014, were audited by the independent auditor Reconta Ernst & Young SpA. The independent auditor of Eni SpA, as the main auditor, is wholly in charge of the auditing activities of the Consolidated Financial Statements; when there are other independent auditors, it takes the responsibility of their work. Amounts in the financial statements and in the notes are expressed in millions of euros (euro million).

2 Principles of consolidation

Subsidiaries
The Consolidated Financial Statements include the financial statements of Eni SpA and those of its subsidiaries. Control of an investee exists when the investor is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. To have power over an investee, the investor must have existing rights that give it the current ability to direct the relevant activities of the investee.

For entities acting as sole-operator in the management of oil and gas contracts on behalf of companies participating in a joint project, the activities are financed proportionally based on a budget approved by the participating companies upon presentation of periodical reports of proceeds and expenses. Costs and revenues and other operating data (production, reserves, etc.) of the project, as well as the related obligations arising from the project, are recognized proportionally directly in the financial statements of the companies involved. Some subsidiaries are not consolidated because they are immaterial, either individually or overall; this exclusion has not produced significant[1] effects on the Consolidated Financial Statements. These investments are accounted for as described below under the item "Non-current financial assets".

The income and expense of a subsidiary are included in the consolidated financial statements from the acquisition date until the date when the parent ceases to control the subsidiary. Assets and liabilities, revenues and expenses related to fully-consolidated subsidiaries are wholly incorporated in the Consolidated Financial Statements; the book value of these subsidiaries is eliminated against the corresponding share of the shareholders equity. Equity and net profit of non-controlling interests are included in specific lines of equity and profit and loss account.

The purchase of additional equity interests in subsidiaries from non-controlling interests is recognized in the Group shareholders equity and represents the excess of the amount paid over the carrying value of the non-controlling interests acquired; similarly, the effects of the sale of non-controlling interests in subsidiaries without loss of control are recognized in equity. Conversely, the sale of equity interests with loss of control determines the recognition in the profit and loss account of: (i) any gain/loss calculated as the difference between the consideration received and the corresponding transferred share of equity; (ii) any gain or loss recognized as a result of remeasuring to fair value any investment retained in the former subsidiary; and (iii) any amount related to the former subsidiary previously recognized in other comprehensive income which can be reclassified subsequently to profit and loss account[2]. Any investment retained in the former subsidiary is recognized at its fair value at the date when control is lost and shall be accounted for in accordance with the applicable measurement criteria. Subsidiaries financial statements are audited by external auditors who audit also the information required for the preparation of the Consolidated Financial Statements.

(1) According to the requirements of the Framework of international accounting standards, information is material if its omission or misstatement could influence the economic decisions that users make on the basis of the financial statements.
(2) Conversely, any component related to the former subsidiary previously recognized in other comprehensive income, which can not be reclassified subsequently to profit and loss account, are reclassified within retained earnings.

Business combinations
Business combination transactions are recognized by applying the acquisition method. The consideration transferred in a business combination is measured at the acquisition date and is the sum of the fair value of the assets transferred, the liabilities incurred, as well as any equity instruments issued by the acquirer. Acquisition-related costs are recognized in profit and loss account when they are incurred. At the acquisition date, the acquirer shall measure the identifiable assets acquired and liabilities assumed at their acquisition-date fair values[3], unless IFRSs provide exceptions to this measurement principle. The surplus of the cost of investment over the Group s share of the net fair value of the identifiable assets and liabilities is recognized as goodwill; a gain from a bargain purchase is recognized in the profit and loss account.

Any non-controlling interest is measured as the proportionate share in the recognized amounts of the acquiree s identifiable net assets at the acquisition date (partial goodwill method); as an alternative, it is allowed the recognition of the entire amount of goodwill deriving from the acquisition, including also the goodwill attributable to non-controlling interests (full goodwill method). In the last case, non-controlling interests are measured at their fair value which therefore includes the goodwill attributable to them[4]. The choice of measurement basis of goodwill (partial goodwill method versus full goodwill method) is made on a transaction-by-transaction basis.

In a business combination achieved in stages, the purchase price is determined by summing the fair value of previously held equity interest in the acquiree and the consideration transferred for the acquisition of control; the previously held equity interest is remeasured at its acquisition-date fair value and the resulting gain or loss, if any, is recognized in profit and loss account. Furthermore, on acquisition of control, any amount of the acquiree previously recognized in other comprehensive income is charged to profit and loss account or in another item of equity, when the amount cannot be reclassified to profit and loss account.

If the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the provisional amounts recognized at the acquisition date shall be retrospectively adjusted within one year from the acquisition date, to reflect new information obtained about facts and circumstances that existed as of the acquisition date.

Interests in joint arrangements
A joint arrangement is an arrangement of which two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. Investments in joint ventures are accounted for using the equity method as described in the item "Non-current financial assets".

A joint operation is a joint arrangement where the parties have rights to the assets and obligations for the liabilities relating to the arrangement. Eni recognizes, on a line-by-line basis in the Consolidated Financial Statements, its share of the assets, liabilities and expenses of these joint operations incurred jointly with the other partners, along with the Group s income from the sale of its share of the output and any liabilities and expenses that the Group has incurred in relation to the joint operation.

Interests in associates
An associate is an entity over which Eni has significant influence, through the power to participate in the financial and operating policy decisions of the investee; investments in associates are accounted for using the equity method as described in the item "Non-current financial assets".

Intercompany transactions

Intercompany transactions and balances, including unrealized profits arising from intragroup transactions have been eliminated.

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(3) Fair value measurement principles are described below under the item "Fair value measurements".

(4) The choice between partial goodwill and full goodwill method is made also for business combinations resulting in the recognition of a gain on bargain purchase in profit and loss account.

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Unrealized profits on transactions between the Group and its equity-accounted entities are eliminated to the extent of the Group s interest in the equity-accounted entity. In both cases, unrealized losses are not eliminated as evidence of an impairment of the asset transferred.

Foreign currency translation

Financial statements of foreign companies having a functional currency other than the euro, that represents the Group s functional currency, are translated into euro using the rates of exchange ruling at the balance sheet date for assets and liabilities, historical exchange rates for equity and average exchange rates for the profit and loss account (source: Bank of Italy). The cumulative amount of exchange rate differences is presented in the separate component of the Group shareholders equity "Cumulative currency translation differences". Where the foreign subsidiary is not wholly owned, the accumulated exchange differences that are attributable to non-controlling interests are allocated to, and recognized as part of, "Non-controlling interest". Cumulative exchange rate differences are charged to the profit and loss account when the entity disposes the entire interest in a foreign operation or at the loss of control of a foreign subsidiary. In these cases, cumulative exchange rate differences are recognized in the profit and loss account s item "Other gain (loss) from investments". On a partial disposal that does not involve loss of control of a subsidiary that includes a foreign operation, the proportionate share of the cumulative exchange rate differences is reattributed to the non-controlling interests in that foreign operation.

Financial statements of foreign subsidiaries which are translated into euro are denominated in the functional currencies of the Countries where the entities operate. The U.S. dollar is the prevalent functional currency for the entities that do not use the euro.

The main foreign exchange rates used to translate the financial statements adopting a different functional currency are indicated below:

(currency amount for euro 1)	Annual average exchange rate 2011	Exchange rate at Dec. 31, 2011	Annual average exchange rate 2012	Exchange rate at Dec. 31, 2012	Annual average exchange rate 2013	Exchange rate at Dec. 31, 2013
U.S. dollar	1.39	1.29	1.28	1.32	1.33	1.38
Pound sterling	0.87	0.84	0.81	0.82	0.85	0.83
Norwegian krone	7.79	7.75	7.48	7.35	7.81	8.36
Australian dollar	1.35	1.27	1.24	1.27	1.38	1.54
Hungarian forint	279.37	314.58	289.25	292.30	296.87	297.04

3 Summary of significant accounting policies

The most significant accounting policies used in the preparation of the Consolidated Financial Statements are described below.

Current assets

Cash and cash equivalents include cash on hand, demand deposits, as well as financial assets originally due within 90 days, readily convertible to known amount of cash and subject to an insignificant risk of changes in value.

Available-for-sale financial assets include financial assets other than derivative financial instruments, loans and receivables, held for trading financial assets and held-to-maturity financial assets.

Held-for-trading financial assets and available-for-sale financial assets are measured at fair value with gains or losses recognized in the profit and loss account under "Finance income (expense)" and to the equity reserve[5] related to other comprehensive income, respectively. Changes in fair value of available-for-sale financial assets recognized in equity are charged to the profit and loss account when the assets are derecognized or impaired. The objective evidence that an impairment loss has occurred is verified considering, interalia, significant breaches of contracts, serious financial difficulties or the risk of bankruptcy and other financial reorganization of the counterparty; impairment losses of available-for-sale financial assets are included in the carrying amount. Interest and dividends

(5) Changes in the carrying amount of available-for-sale financial assets relating to changes in a foreign exchange rates are recognized in the profit and loss account.

on financial assets measured at fair value are accounted for on an accrual basis in "Finance income (expense)"[6] and "Other gain (loss) from investments", respectively. When the purchase or sale of a financial asset is under a contract whose terms require delivery of the asset within the time frame established generally by regulation or convention in the market place concerned, the transaction is accounted for on the settlement date.

Receivables are measured at amortized cost (see item "Non-current financial assets" below). Transferred financial assets are derecognized when the contractual rights to receive the cash flows of the financial assets are transferred together with the risks and rewards of the ownership. Inventories, including compulsory stocks and excluding construction contracts, are stated at the lower of purchase or production cost and net realizable value. Net realizable value is the net amount expected to be realized from the sale of inventories in the normal course of business, or, with reference to inventories of crude oil and petroleum products already included in binding sale contracts, the contractual sale price. Inventories which are principally acquired with the purpose of selling in the near future and generating a profit from fluctuations in price are measured at fair value less costs to sell. The cost for inventories of hydrocarbons (crude oil, condensates and natural gas) and petroleum products is determined by applying the weighted-average cost method on a three-month basis, or monthly, when it is justified by the use and the turnover of inventories of crude oil and petroleum products; the cost for inventories of the Versalis segment is determined by applying the weighted average cost on an annual basis.

Construction contracts are measured using the cost-to-cost method, whereby contract revenue is recognized by reference to the stage of completion of the contract matching it with the contract costs incurred in reaching that stage of completion. Advances are deducted from inventories within the limits of accrued contractual considerations; any excess of such advances over the value of the inventories is recorded as a liability. Losses related to construction contracts are recognized immediately as an expense when it is probable that total contract costs will exceed total contract revenues.

Construction contract not yet invoiced, whose payment will be made in a foreign currency, is translated into euro using the rates of exchange ruling at the balance sheet date and the effect of rate changes is reflected in the profit and loss account.

When take-or-pay clauses are included in long-term natural gas purchase contracts, uncollected gas volumes which imply the "pay" clause, measured using the price formulas contractually defined, are recognized under "Other assets" as "Deferred costs" as a contra to "Other payables" or, after the settlement, to "Cash and cash equivalents". The allocated deferred costs are charged to the profit and loss account: (i) when natural gas is actually delivered the related cost is included in the determination of the weighted-average cost of inventories; and (ii) for the portion which is not recoverable, when it is not possible to collect gas that was previously uncollected within the contractually defined deadlines. Furthermore, the allocated deferred costs are tested for economic recoverability by comparing the related carrying amount and their net realizable value, determined adopting the same criteria described for inventories. Hedging instruments are described in the item "Derivatives".

Non-current assets

Property, plant and equipment[7]

Tangible assets, including investment properties, are recognized using the cost model and stated at their purchase or construction cost including any costs directly attributable to bringing the asset into operation. In addition, when a substantial period of time is required to make the asset ready for use, the purchase price or construction cost includes the borrowing costs incurred that could have otherwise been avoided if the expenditure had not been made. In the case of a present obligation for the dismantling and removal of assets and the restoration of sites, the carrying value includes, with a corresponding entry to a specific provision, the estimated (discounted) costs to be incurred at the moment the asset is retired. Changes in estimate of the carrying amounts of provisions due to the passage of time and changes in discount rates are recognized under "Provisions for contingencies"[8]. Property, plant and equipment are not revalued for financial reporting purposes. Assets carried under financial leasing or concerning arrangements that do not take the legal form of a finance lease but substantially transfer all the risks and rewards of ownership of the leased asset are recognized at fair value, net of grants attributable to the lessee or, if lower, at the present value of the minimum lease payments. Leased assets are included within property, plant and equipment. A corresponding financial debt payable to the lessor is recognized as a financial liability. These assets

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(6) Interests accrued on financial assets held for trading impact the total fair value measurement of the instrument and are recognized, within the item "Finance income (expense)", in the sub-item "Net finance income on financial assets held for trading". Conversely, interests accrued on financial assets available-for-sale are recognized, within the item "Finance income (expense)", in the sub-item "Finance income".

(7) Recognition and evaluation criteria of exploration and production activities are described in the section "Exploration and production activities" below.

(8) The Company recognizes material provisions for the retirement of assets in the Exploration & Production segment. No significant asset retirement obligations associated with any legal obligations to retire refining, marketing and transportation (downstream) and chemical long-lived assets are generally recognized, as undetermined settlement dates for asset retirements do not allow a reasonable estimate of the fair value of the associated retirement obligation. The Company performs periodic reviews of its downstream and chemical long-lived assets for any changes in facts and circumstances that might require recognition of a retirement obligation.

are depreciated using the criteria described below. When the renewal is not reasonably certain, leased assets are depreciated over the shorter of the lease term or the estimated useful life of the asset. Expenditures on renewals, improvements and transformations which provide additional economic benefits are recognized as items of property, plant and equipment when it is probable that they will increase the expected future economic benefits of the asset. Tangible assets, from the moment they begin or should begin to be used, are depreciated systematically using a straight-line method over their useful life which is an estimate of the period over which the assets will be used by the Company. When tangible assets are composed of more than one significant element with different useful lives, each component is depreciated separately. The amount to be depreciated is the book value less the residual value at the end of the useful life, if it is significant and can be reasonably determined. Land is not depreciated, even when purchased with a building. Tangible assets held for sale are not depreciated (see item "Assets held for sale and discontinued operations" below). A change in the depreciation method, deriving from changes in the asset s useful life, in its residual value or in the pattern of consumption of the economic benefits embodied in the asset, shall be recognized prospectively. Assets that can be used free of charge by third parties are depreciated over the shorter term of the duration of the concession or the asset s useful life. Replacement costs of identifiable components in complex assets are capitalized and depreciated over their useful life; the residual book value of the component that has been substituted is charged to the profit and loss account. Expenditures for ordinary maintenance and repairs are expensed as incurred. The carrying value of property, plant and equipment is reviewed for impairment whenever events indicate that the carrying amounts for those assets may not be recoverable. The recoverability of an asset is assessed by comparing its carrying value with the recoverable amount, which is the higher of fair value less costs to sell or its value-in-use. Value-in-use is the present value of the future cash flows expected to be derived from the use of the asset and, if significant and reasonably determinable, the cash flows deriving from its disposal at the end of its useful life, net of disposal costs. Expected cash flows are determined on the basis of reasonable and supportable assumptions that represent management s best estimate of the range of economic conditions that will exist over the remaining useful life of the asset, giving greater weight to external evidence. Oil, natural gas and petroleum products prices (and to prices for products which derive there from) used to quantify the expected future cash flows are estimated based on forward prices prevailing in the marketplace for the first four years and management s long-term planning assumptions thereafter. Discounting is carried out at a rate that reflects a current market valuation of the time value of money and of those specific risks of the asset that are not reflected in the estimate of the future cash flows. In particular, the discount rate used is the Weighted Average Cost of Capital (WACC) adjusted for the specific Country risk of the activity. The evaluation of the specific Country risk to be included in the discount rate is provided by external parties. WACC differs considering the risk associated with each operating segments; in particular for the assets belonging to the Gas & Power and Engineering & Construction segments, taking into account their different risk compared with Eni as a whole, specific WACC rates have been defined (for Gas & Power segment on the basis of a sample of companies operating in the same segment; for Engineering & Construction segment on the basis of the market quotation); WACC used for impairment reviews in the Gas & Power segment is adjusted to take into consideration the risk premium of the specific Country of the activity while WACC used for impairment reviews in the Engineering & Construction segment is not adjusted for Country risk as most of the assets are not located in a specific Country. For the other segments, a single WACC is used considering that the risk is the same to that of Eni as a whole. Value-in-use is calculated net of the tax effect as this method results in values similar to those resulting from discounting pre-tax cash flows at a pre-tax discount rate deriving, through an iteration process, from a post-tax valuation. Valuation is carried out for each single asset or, if the recoverable amount of a single asset cannot be determined, for the smallest identifiable group of assets that generates independent cash inflows from their continuous use, the so-called "cash generating unit". When an impairment loss no longer exists, a reversal of the impairment loss is recognized in the profit and loss account. The reversal cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

Intangible assets

Intangible assets are identifiable assets without physical substance, controlled by the Company and able to produce future economic benefits, and goodwill acquired in business combinations. An asset is classified as intangible when management is able to distinguish it clearly from goodwill. This condition is normally met when: (i) the intangible asset arises from contractual or legal rights, or (ii) the asset is separable, i.e. can be sold, transferred, licensed, rented or exchanged, either individually or together with other assets. An entity controls an asset if it has the power to obtain the future economic benefits flowing from the underlying asset and to restrict the access of others to those benefits. Intangible assets are initially stated at cost as determined by the criteria used for tangible assets and they are not revalued for financial reporting purposes. Intangible assets with a definite useful life are amortized systematically over their useful life estimated as the period over which the assets will be used by the Company; the amount to be amortized and the recoverability of the carrying amount are determined in accordance with the criteria described in the item "Property, plant and equipment".

Goodwill and other intangible assets with an indefinite useful life are not amortized. Their carrying values are reviewed for impairment at least annually and whenever events or changes in circumstances indicate that the carrying value may be impaired. Goodwill is tested for impairment at the lowest level within the entity at which it is monitored for internal management purposes. When the carrying amount of the cash generating unit, including goodwill allocated thereto, calculated considering any impairment loss of the non-current assets belonging to the cash generating unit, exceeds its recoverable amount[9], the excess is recognized as an impairment loss. The impairment loss is first allocated to reduce the carrying amount of goodwill; any remaining excess to be allocated to the assets of the unit is applied pro-rata on the basis of the carrying amount of each asset in the unit. Impairment charges against goodwill are not reversed[10]. Costs of technological development activities are capitalized when: (i) the cost attributable to the development activity can be reliably determined; (ii) there is the intention, availability of financial and technical resources to make the asset available for use or sale; and (iii) it can be demonstrated that the asset is able to generate future economic benefits. Intangible assets also include public to private service concession arrangements concerning the development, financing, operation and maintenance of infrastructures under concession, in which the grantor: (i) controls or regulates what services the operator must provide with the infrastructure, and at what price; and (ii) controls by the ownership, beneficial entitlement or otherwise any significant residual interest in the infrastructure at the end of the concession arrangement. According to the agreements, the operator has the right to operate the infrastructure, controlled by the grantor, in order to provide the public service[11].

Exploration and production activities[12]

Acquisition of mineral rights
Costs associated with the acquisition of mineral rights are capitalized in connection with the assets acquired (such as exploratory potential, probable and possible reserves and proved reserves). When the acquisition is related to a set of exploratory potential and reserves, the cost is allocated to the different assets acquired on the basis of the value of the expected discounted cash flows. Expenditure for the exploratory potential, represented by the costs for the acquisition of the exploration permits and for the extension of existing permits, is recognized under "Intangible assets" and is amortized on a straight-line basis over the period of the exploration as contractually established. If the exploration is abandoned, the residual expenditure is charged to the profit and loss account. Acquisition costs for proved reserves and for possible and probable reserves are recognized in the balance sheet as assets. Costs associated with proved reserves are amortized on a UOP basis, as detailed in the section "Development", considering both developed and undeveloped reserves. Expenditures associated with possible and probable reserves are not amortized until classified as proved reserves; in case of a negative result, the costs are charged to the profit and loss account.

Exploration
Costs associated with exploratory activities for oil and gas producing properties incurred both before and after the acquisition of mineral rights (such as acquisition of seismic data from third parties, test wells and geophysical surveys) are initially capitalized in order to reflect their nature as an investment and subsequently amortized in full when incurred.

Development
Development expenditures are those costs incurred to obtain access to proved reserves and to provide facilities for extracting, gathering and storing oil and gas. They are then capitalized within property, plant and equipment and amortized generally on a UOP basis, as their useful life is closely related to the availability of economically producible reserves. This method provides for residual costs at the end of each quarter to be amortized at a rate representing the ratio between the volumes extracted during the quarter and the proved developed reserves existing at the end of the quarter, increased by the volumes extracted during the quarter. This method is applied with reference to the smallest aggregate representing a direct correlation between development expenditures and proved developed reserves. Costs related to unsuccessful development wells or damaged wells are expensed immediately as losses on disposal. Development costs are tested for impairment in accordance with the criteria described in the section "Property, plant and equipment".

Production

Production costs are those costs incurred to operate and maintain wells and field equipment and are expensed as incurred.

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(9) For the definition of recoverable amount see item "Property, plant and equipment".

(10) Impairment charges recognized in an interim period are not reversed also when, considering conditions existing in a subsequent interim period, they would have been recognized in a smaller amount or would not have been recognized.

(11) When the operator has an unconditional contractual right to receive cash or another financial asset from or at the direction of the grantor, considerations received or receivable by the operator for construction or upgrade of infrastructure are recognized as a financial asset.

(12) IFRS does not have specific criteria for hydrocarbon exploration and production activities. Eni continues to use existing accounting policies for exploration and evaluation of assets previously applied before the introduction of IFRS 6 "Exploration for and evaluation of mineral resources".

Production sharing agreements and buy-back contracts
Oil and gas reserves related to production-sharing agreements and buy-back contracts are determined on the basis of contractual clauses related to the repayment of costs incurred for the exploration, development and production activities executed through the use of Company s technologies and financing (cost oil) and the Company s share of production volumes not destined to cost recovery (profit oil). Revenues from the sale of the production entitlements against both cost oil and profit oil are accounted for on an accrual basis whilst exploration, development and production costs are accounted for according to the policies mentioned above. The Company s share of production volumes and reserves representing the profit oil includes the share of hydrocarbons which corresponds to the taxes to be paid, according to the contractual agreement, by the national government on behalf of the Company. As a consequence, the Company has to recognize at the same time an increase in the taxable profit, through the increase of the revenues, and a tax expense.

Retirement
Costs expected to be incurred with respect to the retirement of a well, including costs associated with removal of production facilities, dismantlement and site restoration, are capitalized, consistently with the policy described under "Property, plant and equipment", and then amortized on a UOP basis.

Grants
Grants related to assets are recognized as a reduction of purchase price or production cost of the related assets when there is reasonable assurance that the conditions attaching to them, agreed upon with the grantor government, have been fulfilled. Grants not related to capital expenditure are recognized in the profit and loss account on an accrual basis matching the related costs when incurred.

Non-current financial assets

Investments
Investments in subsidiaries excluded from consolidation, joint ventures and associates are accounted for using the equity method[13]. Under the equity method, investments are initially recognized at cost, allocating any difference between the cost of the investment and the investor s share of the net fair value of the investee s identifiable net assets analogously to the recognition principles of business combination. Subsequently, the carrying amount is adjusted to reflect: (i) the investor s share of the post-acquisition profit or loss of the investee; and (ii) the investor s share of the investee s other comprehensive income. The changes in the equity of investees accounted for using the equity method, not arising from the profit or loss or from the other comprehensive income, are recognized in the investor s profit and loss account, as they represent, basically, a gain or loss from a disposal of an interest of the investee s equity. Distributions received from an investee are recorded as a reduction of the carrying amount of the investment. In applying the equity method, consolidations adjustments are considered (see also "Principles of consolidation" paragraph). When there is objective evidence of impairment (see also item "Current assets"), the recoverability is tested by comparing the carrying amount and the related recoverable amount determined by adopting the criteria indicated in the item "Property, plant and equipment". Subsidiaries excluded from consolidation, joint ventures and associates are accounted for at cost, net of impairment losses if this does not result in a misrepresentation of the Company s financial condition. When an impairment loss no longer exists, a reversal of the impairment loss is recognized in profit and loss account within "Other gain (loss) from investments". The reversal cannot exceed the previously recognized impairment losses.

The sale of equity interests with loss of joint control or significant influence over the investee determines the recognition in the profit and loss account of: (i) any gain/loss calculated as the difference between the consideration received and the corresponding transferred share; (ii) any gain or loss recognized as a result of remeasuring to fair value any investment retained in the former joint venture/associate[14]; and (iii) any amount related to the former joint venture/associate previously recognized in other comprehensive income which can be reclassified subsequently to profit and loss account[15]. Any investment retained in the former joint venture/associate is recognized at its fair value at the date when joint control or significant influence are lost and shall be accounted for in accordance with the applicable measurement criteria. Other investments, included in non-current assets, are recognized at their fair value and their effects are included in the equity reserve related to other comprehensive income; the changes in fair value recognized in equity are charged to the profit and loss account when it is impaired or realized. Galp and Snam shares related to convertible bonds are measured at fair value through profit and loss account, under the fair value option,

(13) In the case of step acquisition of a significant influence (or joint control), the investment is recognized, at the acquisition date of significant influence (joint control), at the amount deriving from the use of the equity method assuming the adoption of this method since initial acquisition; the "step-up" of the carrying amount of interests owned before the acquisition of significant influence (joint control) is taken to equity.

(14) If the retained investment continues to be accounted for using the equity method, no remeasurement to fair value is recognized in profit and loss account.

(15) Conversely, any component related to the former joint venture/associate previously recognized in other comprehensive income, which can not be reclassified subsequently to profit and loss account, are reclassified within retained earnings.

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in order to significantly reduce the accounting mismatch with the recognition of the option embedded in the convertible bond, measured at fair value through profit and loss account. When investments are not traded in a public market and their fair value cannot be reasonably determined, they are accounted for at cost, net of impairment losses; impairment losses shall not be reversed[16]. The investor s share of losses of an investee, that exceeds its interest in the investee, is recognized in a specific provision only to the extent the investor is required to fulfill legal or constructive obligations of the investee or to cover its losses.

Receivables and financial assets to be held to maturity
Receivables and financial assets to be held to maturity are stated at cost represented by the fair value of the initial exchanged amount adjusted to take into account direct external costs related to the transaction (e.g. fees of agents or consultants, etc.). The initial carrying value is then adjusted to take into account principal repayments, reductions for impairment or uncollectibility and amortization of any difference between the maturity amount and the initial amount. Amortization is carried out on the basis of the effective interest rate represented by the rate that equalizes, at the moment of the initial recognition, the present value of expected cash flows to the initial carrying amount (so-called "amortized cost method"). Receivables for finance leases are recognized at an amount equal to the present value of the lease payments and the purchase option price or any residual value; the amount is discounted at the interest rate implicit in the lease. If there is objective evidence that an impairment loss has been incurred (see also point "Current assets"), the impairment loss is measured by comparing the carrying value with the present value of the expected cash flows discounted at the effective interest rate as defined at initial recognition, or at the moment of its updating to reflect re-pricings contractually established. Receivables and financial assets to be held to maturity are presented net of the allowance for impairment losses; when the impairment loss is definite the allowance for impairment losses is reversed for charges, otherwise for excess. Changes to the carrying amount of receivables or financial assets in accordance with the amortized cost method are recognized as "Finance income (expense)".

Assets held for sale and discontinued operations
Non-current assets and current and non-current assets included within disposal groups, are classified as held for sale if their carrying amount will be recovered principally through a sale transaction rather than through their continuing use. For this to be the case, the sale must be highly probable and the asset or the disposal group must be available for immediate sale in its present condition. Non-current assets held for sale, current and non-current assets included within disposal groups that have been classified as held for sale and the liabilities directly associated with them are recognized in the balance sheet separately from the entity s other assets and liabilities. Non-current assets held for sale are not depreciated and they are measured at the lower of the fair value less costs to sell and their carrying amount. After the classification as held for sale of equity-accounted investments, the investment, or the portion of the investment, that meets the criteria to be classified as held for sale, is no longer accounted for using the equity method. Any retained portion of the equity-accounted investment that has not been classified as held for sale is accounted for using the equity method until disposal of the portion that is classified as held for sale takes place. After the disposal takes place, any retained investment is measured consistently with the applicable IFRSs.

Any difference between the carrying amount and the fair value less costs to sell is taken to the profit and loss account as an impairment loss; any subsequent reversal is recognized up to the cumulative impairment losses, including those recognized prior to qualification of the asset as held for sale. Non-current assets and current and non-current assets included within disposal groups, classified as held for sale, are considered a discontinued operation if, alternatively: (i) represent a separate major line of business or geographical area of operations; (ii) are part of a disposal program of a separate major line of business or geographical area of operations; or (iii) are a subsidiary acquired exclusively with a view to resale. The results of discontinued operations, as well as any gain or loss recognized on the disposal, are indicated in a separate profit and loss account item, net of the related tax effects; the economic figures of discontinued operations are indicated also for prior periods presented in the financial statements. When there is a sale plan involving loss of control of a subsidiary, all the assets and liabilities of that subsidiary are classified as held for sale, regardless of whether a non-controlling interest in its former subsidiary will be retain after the sale.

Financial liabilities

Debt is measured at amortized cost (see item "Non-current financial assets" above). Financial liabilities are derecognized when they are extinguished, or when the obligation specified in the contract is discharged or cancelled or expires.

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(16) Impairment charges recognized in an interim period are not reversed also when, considering conditions existing in a subsequent interim period, they would have been recognized in a smaller amount or would not have been recognized.

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Provisions for contingencies

Provisions for contingencies are liabilities for expenses and charges of a definite nature and whose existence is certain or probable but for which at year end the timing or amount of future expenditure is uncertain. Provisions are recognized when: (i) there is a present obligation, legal or constructive, as a result of a past event; (ii) it is probable that the settlement of that obligation will result in an outflow of resources embodying economic benefits; and (iii) the amount of the obligation can be reliably estimated. The amount recognized as a provision is the best estimate of the expenditure required to settle the present obligation at the balance sheet date or to transfer it to third parties at that time. The amount recognized for onerous contracts is the lower of the cost necessary to fulfill the obligations, net of expected economic benefits deriving from the contracts, and any indemnity or penalty arising from failure to fulfill these obligations. If the effect of the time value is material, and the payment date of the obligations can be reasonably estimated, provisions to be accrued are the present value of the expenditures expected to be required to settle the obligation at a discount rate that reflects the Company s average borrowing rate taking into account the risks associated with the obligation. The increase in the provision due to the passage of time is recognized as "Finance income (expense)". When the liability regards a tangible asset (e.g. site dismantling and restoration), the provision is stated with a corresponding entry to the asset to which it refers. Charges to the profit and loss account are made with the amortization process. Costs that the Company expects to bear in order to carry out restructuring plans are recognized when the Company has a detailed formal plan for the restructuring and has raised a valid expectation in the affected parties that it will carry out the restructuring. Provisions are periodically reviewed and adjusted to reflect changes in the estimates of costs, timing and discount rates. Changes in provisions are recognized in the same profit and loss account item that had previously held the provision, or, when the liability regards tangible assets (i.e. site dismantling and restoration), changes in the provision are recognized with a corresponding entry to the assets to which they refer, to the extent of the assets carrying amounts; any excess amount is recognized to the profit and loss account. In note 28 Provisions for contingencies, the following contingent liabilities are described: (i) possible, but not probable obligations arising from past events, whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the Company s control; and (ii) present obligations arising from past events whose amount cannot be reliably measured or whose settlement will probably not result in an outflow of resources embodying economic benefits.

Provisions for employee benefits

Post-employment benefit plans, including informal arrangements, are classified as either defined contribution plans or defined benefit plans depending on the economic substance of the plan as derived from its principal terms and conditions. In the first case, the Company s obligation, which consists of making payments to the State or a trust or a fund, is determined on the basis of contributions due. The liabilities related to defined benefit plans, net of any plan assets, are determined on the basis of actuarial assumptions and charged on an accrual basis during the employment period required to obtain the benefits. Net interest includes the return on plan assets and the interests cost to be recognized in the profit and loss account. Net interest is measured by applying to the liability, net of any plan assets, the discount rate used to calculate the present value of the liability; net interest of defined benefit plans is recognized in "Finance income (expense)". Remeasurements of the net defined benefit liability, comprising actuarial gains and losses, resulting from changes in the actuarial assumptions used or from changes arising from experience adjustments, and the return on plan assets excluding amounts included in net interest, are recognized within statement of comprehensive income. Furthermore, in presence of net assets, changes in their value different from those included in net interest are recognized within statement of comprehensive income. Obligations for long-term benefits are determined by adopting actuarial assumptions. The effects of remeasurements are taken to profit and loss account in their entirety.

Treasury shares

Treasury shares are recognized as deductions from equity at cost. Gains or losses resulting from subsequent sales are recognized in equity.

Revenues and costs

Revenues associated with sales of products and services are recognized when significant risks and rewards of ownership have passed to the customer or when the transaction can be considered settled and the associated revenue can be reliably measured. In particular, revenues are recognized for the sale of:

- crude oil, generally upon shipment;
- natural gas, upon delivery to the customer;
- petroleum products sold to retail distribution networks, generally upon delivery to the service stations, whereas all other sales of petroleum products are generally recognized upon shipment; and
- chemical products and other products, generally upon shipment.

Revenues are recognized upon shipment when, at that date, significant risks are transferred to the buyer. Revenues from crude oil and natural gas production from properties in which Eni has an interest together with other producers are recognized on the basis of Eni s net working interest in those properties (entitlement method). Differences between Eni s net working interest volume and actual production volumes are recognized at current prices at year end. Revenues related to partially rendered services are recognized by reference to the stage of completion, provided that: (i) the amount of revenues can be measured reliably; (ii) it is probable that the economic benefits associated with the transaction will flow to the entity; (iii) the stage of completion of the transaction at the end of the reporting period can be measured reliably; and (iv) the related costs can be measured reliably. When the outcome of the transaction involving the rendering of services cannot be estimated reliably, revenue is recognized only to the extent of the expenses recognized that are recoverable. Revenues accrued during the year related to construction contracts are recognized on the basis of contractual revenues with reference to the stage of completion of a contract measured on the cost-to-cost basis. For service concession arrangements (see item "Intangible assets" above) in which customers fees do not provide a reliable distinction between the compensation for construction/update of the infrastructure and the compensation for operating it and in the absence of external benchmarks, revenues recognized during the construction/update phase are limited to the amount of the costs incurred. Additional revenues, derived from a change in the scope of work, are included in the total amount of revenues when it is probable that the customer will approve the variation and the related amount. Claims deriving from additional costs incurred for reasons attributable to the customer are included in the total amount of revenues when it is probable that the counterparty will accept them. Tangible assets, different from an infrastructure used in service concession arrangements, transferred from customers (or constructed using cash transferred from customers) and used to connect them to a network to supply goods and services, are recognized at their fair value as an offset to revenues. When more than one separately identifiable service is provided (for example, connection to a network and supply of goods) the entity shall assess for which one service it receives the transferred asset from the customer and it shall consistently recognize a revenue when the connection is delivered or over the lesser period between the length of the supply and the useful life of the transferred asset. Revenues are measured at the fair value of the consideration received or receivable net of returns, discounts, rebates, bonuses and related taxation. Award credits, related to customer loyalty programs, are recognized as a separate component of the sales transaction which grants the right to customers. Therefore, the portion of revenues related to the fair value of award credits granted is recognized as an offset to the item "Other liabilities". The liability is charged to the profit and loss account in the period in which the award credits are redeemed by customers or the related right is lost. The exchange of goods and services of a similar nature and value do not give rise to revenues and costs as they do not represent sale transactions. Costs are recognized when the related goods and services are sold or consumed during the year, they are systematically allocated or when their future economic benefits cannot be identified. Costs associated with emission quotas, determined on the basis of the market prices, are recognized in relation to the amount of the carbon dioxide emissions that exceed free allowances. Costs related to the purchase of the emission rights are recognized as intangible assets net of any negative difference between the amount of emissions and the free allowances. Revenues related to emission quotas are recognized when they are sold. In case of sale, if applicable, the acquired emission rights are considered as the first to be sold. Monetary receivables granted as a substitution of emission rights awarded free of charge are recognized as a contra to item "Other income and revenues" of the profit and loss account. Operating lease payments are recognized in the profit and loss account over the length of the contract. Payroll costs include stock options granted to managers, consistent with their actual remunerative nature. The instruments granted are recorded at fair value on the vesting date and are not subject to subsequent adjustments; the current portion is calculated pro-rata over the vesting period[17]. The fair value of stock options is determined using valuation techniques which consider conditions related to the exercise of options, current share prices, expected volatility and the risk-free interest rate. The fair value of stock options is recognized as a contra to the equity item "Other reserves". The costs for the acquisition of new knowledge or discoveries, the study of products or alternative processes, new techniques or models, the planning and construction of prototypes or, in any case, costs incurred for other scientific research activities or technological development, which cannot be capitalized (see item "Intangible assets" above), are included in the profit and loss account when they are incurred.

Exchange rate differences

Revenues and costs associated with transactions in currencies other than the functional currency are translated into the functional currency by applying the exchange rate at the date of the transaction. Monetary assets and liabilities denominated in currencies other than functional currency are converted by applying the year-end exchange rate and the effect is stated in the profit and loss account. Non-monetary assets and liabilities denominated in currencies other than the functional currency valued at cost are translated at the initial exchange rate. Non-monetary items that are measured at fair value, recoverable amount or net realizable value are translated using the exchange rate at the date when the value is determined.

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(17) The period between the date of the award and the date at which the option can be exercised.

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Dividends
Dividends are recognized at the date of the general shareholders meeting in which they were declared, except when the sale of shares before the ex-dividend date is certain.

Income taxes
Current income taxes are determined on the basis of estimated taxable income. The estimated liability is included in "Income taxes payable". Current income tax assets and liabilities are measured at the amount expected to be paid to (recovered from) the tax authorities, using tax rates and the tax laws that have been enacted or substantively enacted by the end of the reporting period. Deferred tax assets or liabilities are recognized for temporary differences arising between the carrying amounts of the assets and liabilities and their tax bases, based on tax rates and tax laws that have been enacted or substantively enacted for future years. Deferred tax assets are recognized when their recoverability is considered probable; in particular, deferred tax assets are recoverable when it is probable that taxable income will be available in the same year as the reversal of the deductible temporary difference. Similarly, deferred tax assets for the carry-forward of unused tax credits and unused tax losses are recognized to the extent that the recoverability is probable. Relating to the temporary differences associated with investments in subsidiaries, associates and interests in joint arrangements, the related deferred tax liabilities are not recognized if the company is able to control the timing of reversal of the temporary differences and it is probable that the temporary difference will not reverse in the foreseeable future. Deferred tax assets and liabilities are included in non-current assets and liabilities and are offset at a single entity level if related to offsettable taxes. The balance of the offset, if positive, is recognized in the item "Deferred tax assets"; if negative, in the item "Deferred tax liabilities". When the results of transactions are recognized directly in shareholders equity, the related current and deferred taxes are also charged to the shareholders equity.

Derivatives
Derivatives, including embedded derivatives which are separated from the host contract, are assets and liabilities measured at their fair value. Derivatives are designated as hedging instruments when the relationship between the derivative and the hedged item is formally documented and the hedge is highly effective and regularly reviewed. When hedging instruments hedge the risk of changes of the fair value of the hedged item (fair value hedge, e.g. hedging of the variability on the fair value of fixed interest rate assets/liabilities), the derivatives are measured at fair value through profit and loss account. Hedged items are consistently adjusted to reflect, in the profit and loss account, the changes of fair value associated with the hedged risk; this applies even if the hedged item should be otherwise measured. When derivatives hedge the cash flow variability risk of the hedged item (cash flow hedge, e.g. hedging the variability on the cash flows of assets/liabilities as a result of the fluctuations of exchange rate), the changes in the fair value of the derivatives, considered an effective hedge, are initially recognized in the equity reserve related to other comprehensive income and then reclassifies to profit and loss account in the same period during which the hedged transaction affects the profit and loss account. The changes in the fair value of derivatives that do not meet the conditions required to qualify for hedge accounting are recognized in the profit and loss account. In particular, the changes in the fair value of non-hedging derivatives on interest rates and exchange rates are recognized in the profit and loss account item "Finance income (expense)"; conversely, the changes in the fair value of non-hedging derivatives on commodities are recognized in the profit and loss account item "Other operating (expense) income". Economic effects of transactions to buy or sell commodities entered into to meet the entity s normal operating requirements and for which the settlement is provided with the delivery of the underlying, are recognized on an accrual basis (the so-called normal sale and normal purchase exemption or own use exemption).

Fair value measurements
Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants (not in a forced liquidation or a distress sale) at the measurement date (exit price). Fair value measurement is based on the market conditions existing at the measurement date and on the assumptions of market participants (market-based measurement). A fair value measurement assumes that the transaction to sell the asset or transfer the liability takes place in the principal market for the asset or liability, or in the absence of a principal

market, in the most advantageous market to which the entity has access, independently from the entity s intention to sell the asset or transfer the liability to be measured.

A fair value measurement of a non-financial asset takes into account a market participant s ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use. Highest and best use is determined from the perspective of market participants, even if the entity intends a different use; an entity s current use of a non-financial asset is presumed to be its highest and best use, unless market or other factors suggest that a different use by market participants would maximize the value of the asset.

The fair value of a liability, both financial and non-financial, or of an equity instrument, in the absence of a quoted price, is measured from the perspective of a market participant that holds the identical item as an asset at the measurement date. The fair value of a liability reflects the effect of a non-performance risk. Non-performance risk includes, but may not be limited to, an entity s own credit risk.

In the absence of available market quotation, fair value is measured by using valuation techniques that are appropriate in the circumstances, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs.

4 Financial statements and changes in accounting policies

Financial statements[18]

Assets and liabilities on the balance sheet are classified as current and non-current. Items on the profit and loss account are presented by nature[19]. The statement of comprehensive income shows net profit integrated with income and expenses that are recognized directly in equity according to IFRS. The statement of changes in shareholders equity includes the comprehensive income for the year, transactions with shareholders in their capacity as shareholders and other changes in shareholders equity. The statement of cash flows is presented using the indirect method, whereby net profit is adjusted for the effects of non-cash transactions.

Changes in accounting policies

The revised IAS 19 "Employee Benefits" (hereinafter "IAS 19") requires immediately recognition of actuarial gains and losses and the return on plan assets arising in connection with defined benefit plans. Remeasurements of defined benefit plans are recognized in other comprehensive income. Previously, Eni applied the corridor method of accounting under which amounts falling inside the corridor remained unrecognized, while amounts falling outside it were recognized (amortized) in profit and loss account over the expected average remaining working lives of the employees participating in the plan.

In May 2011, the IASB issued IFRS 10 "Consolidated Financial Statements" and IFRS 11 "Joint Arrangements". IFRS 10 provides a new definition of control to be consistently applied to all entities (included vehicles). According to this definition, an entity controls an investee when it is exposed, or has rights, to its returns from its involvement and has the ability to affect those returns through its power over the investee. IFRS 11 establishes a principle that applies to the accounting for all joint arrangements, whereby parties to the arrangement account for their underlying contractual rights and obligations relating to the joint arrangement. IFRS 11 identifies two types of joint arrangements. A "joint venture" is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. A "joint operation" is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. Investments in joint ventures are accounted for using the equity method. Investments in joint operations are accounted for by recognizing the group s assets, liabilities, revenue and expenses relating to the joint operation.

(18) The financial statements are the same reported in the Annual Report on Form 20-F 2012, except for: (i) the statement of comprehensive income where, based on the amendments of IAS 1 "Presentation of Financial Statements", other comprehensive income are grouped on the basis of their possibility to be reclassified subsequently to profit and loss account in accordance with the applicable IFRSs (reclassification adjustments); and (ii) the adoption of the new provisions of IAS 19, whose effects are described in the item "Changes in accounting policies".

(19)

Further information on financial instruments as classified in accordance with IFRS is provided in note 35   Guarantees, commitments and risks - Other information about financial instruments.

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The main impact of these new standards relates to certain of the Group s former jointly controlled entities, which were equity-accounted, now fall under the definition of a joint operation under IFRS 11.

The opening balances at January 1, 2012 and comparative information for year ended December 31, 2012 have been restated in the Consolidated Financial Statements as a result of the adoption of IFRS 10 "Consolidated Financial Statements", IFRS 11 "Joint Arrangements" and the amended IAS 19 "Employee Benefits". The quantitative impact on the financial statements is provided below:

(euro million)

Selected line items only	As reported	IFRS 10/IFRS 11	IAS 19R	As restated
January 1, 2012				
Current assets	38,195	203	103	38,501
Non-current assets	104,520	182	58	104,760
- of which property, plant and equipment	*73,578*	*1,403*		*74,981*
- of which equity-accounted investments	*5,843*	*(815)*	*(4)*	*5,024*
Current liabilities	35,632	45		35,677
Non-current liabilities	46,896	491	222	47,609
- of which provision for employee benefit	*1,039*	*27*	*222*	*1,288*
Total Shareholders Equity	60,393	(151)	(61)	60,181
December 31, 2012				
Current assets	48,742	128	126	48,996
Non-current assets	90,383	185	112	90,680
- of which property, plant and equipment	*63,466*	*1,332*		*64,798*
- of which equity-accounted investments	*4,265*	*(810)*	*(2)*	*3,453*
Current liabilities	33,986	(34)		33,952
Non-current liabilities	42,581	488	393	43,462
- of which provision for employee benefit	*982*	*32*	*393*	*1,407*
Total Shareholders Equity	62,713	(141)	(155)	62,417
2012				
Revenue	128,766	(109)		128,657
Operating profit	15,026	137	45	15,208
Finance income and expense	(1,307)	(24)	(40)	(1,371)
Income (expense) from investments	2,881	(92)		2,789
Net profit for the period	8,673	3	3	8,679
- attributable to Eni	7,788		2	7,790
- attributable to non-controlling interest	885	3	1	889
Net cash provided by operating activities	12,371	196		12,567
Net cash used in investing activities	(8,291)	(86)		(8,377)
Net cash used in financing activities	2,201	(130)		2,071
Net cash flow for the period	6,265	(20)		6,245

Disclosures regarding interest in other entities are presented according to IFRS 12 "Disclosure of interests in other entities" that is effective starting from January 1, 2013.

Furthermore, starting from January 1, 2013, IFRS 13 "Fair value measurement" is effective which provides a framework for fair value measurements, required or permitted by other IFRSs, and for the disclosures about fair value measurements. The effect of adoption of IFRS 13 is not material.

5 Use of accounting estimates

The preparation of the Consolidated Financial Statements requires the use of estimates and assumptions that affect the assets, liabilities, revenues and expenses reported in the financial statements, as well as amounts included in the notes thereto, including discussion and disclosure of contingent liabilities. Estimates made are based on complex or subjective judgments and past experience of other assumptions deemed reasonable in consideration of the information available at the time. The accounting policies and areas that require the most significant judgments and estimates to be used in the preparation of the Consolidated Financial Statements are in relation to the accounting for oil and natural gas activities, specifically in the determination of proved and proved developed reserves, impairment of fixed assets, intangible assets and goodwill, asset retirement obligations, business combinations, pensions and other post-retirement benefits, recognition of environmental liabilities and recognition of revenues in the oilfield services construction and engineering businesses. Although the Company uses its best estimates and judgments, actual results could differ from the estimates and assumptions used. A summary of significant estimates follows.

Oil and gas activities

Engineering estimates of the Company s oil and gas reserves are inherently uncertain. Proved reserves are the estimated volumes of crude oil, natural gas and gas condensates, liquids and associated substances which geological and engineering data demonstrate that can be economically producible with reasonable certainty from known reservoirs under existing economic conditions and operating methods. Although there are authoritative guidelines regarding the engineering and geological criteria that must be met before estimated oil and gas reserves can be designated as "proved", the accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Field reserves will only be categorized as proved when all the criteria for attribution of proved status have been met. At this stage, all booked reserves are classified as proved undeveloped. Volumes are subsequently reclassified from proved undeveloped to proved developed as a consequence of development activity. The first proved developed bookings occur at the point of first oil or gas production. Major development projects typically take one to four years from the time of initial booking to the start of production. Eni reassesses its estimate of proved reserves periodically. The estimated proved reserves of oil and natural gas may be subject to future revision and upward and downward revision may be made to the initial booking of reserves due to production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity. In particular, changes in oil and natural gas prices could impact the amount of Eni s proved reserves in regards to the initial estimate and, in the case of production sharing agreements and buy-back contracts, the share of production and reserves to which Eni is entitled. Accordingly, the estimated reserves could be materially different from the quantities of oil and natural as that ultimately will be recovered. Oil and natural gas reserves have a direct impact on certain amounts reported in the Consolidated Financial Statements. Estimated proved reserves are used in determining depreciation and depletion expenses and impairment expense. Depreciation and depletion rates on oil and gas assets using the UOP basis are determined from the ratio between the amount of hydrocarbons extracted in the quarter and proved developed reserves existing at the end of the quarter increased by the amounts extracted during the quarter. Assuming all other variables are held constant, an increase in estimated proved developed reserves for each field decreases depreciation and depletion expense. Conversely, a decrease in estimated proved developed reserves increases depreciation and depletion expense. In addition, estimated proved reserves are used to calculate future cash flows from oil and gas properties, which are used to assess any impairment loss. The larger is the volume of estimated reserves, the lower is the likelihood of asset impairment.

Impairment of assets

Assets are impaired when there are events or changes in circumstances that indicate the carrying values of the assets are not recoverable. Such impairment indicators include changes in the Group s business plans, changes in commodity prices leading to unprofitable performance, a reduced utilization of the plants and, for oil and gas properties, significant downward revisions of estimated proved reserve quantities or significant increase of the estimated development costs. Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain and complex matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses, production profiles and the outlook for global or regional market supply and demand conditions for crude oil, natural gas, commodity chemicals and refined products. Similar remarks are valid for the physical recoverability of assets recognized in the balance sheet (deferred costs see also item "Current assets") related to natural gas volumes not collected under long-term purchase contracts with take-or-pay clauses as well as for the recoverability of deferred tax assets. The amount of an impairment loss is determined by comparing the book value of an asset with its recoverable amount. The recoverable amount is the greater of fair value net of disposal cost or the value-in-use. The estimated value-in-use is based on the present values of expected future cash flows net of disposal costs. The expected future cash flows used for impairment analyses are based on judgmental assessments of future production volumes, prices and costs, considering available information at the date of review and are discounted by using a rate which considers the risks specific to the asset. For oil and natural gas properties, the expected future cash flows are estimated principally based on developed and non-developed proved reserves including, among other elements, production taxes and the costs to be incurred for the reserves yet to be developed. Oil, natural gas and petroleum product prices (and prices from products which are derived there from) used to quantify the expected future cash flows are estimated based on forward prices prevailing in the marketplace for the first four years and management s long-term planning assumptions thereafter. The estimate of the future amount of production is based on assumptions related to the commodity future prices, lifting and development costs, field decline rates, market demand and other factors. The discount rate reflects the current

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market valuation of the time value of money and of the specific risks of the asset not reflected in the estimate of the future cash flows. Goodwill and other intangible assets with an indefinite useful life are not subject to amortization. The Company tests for impairment such assets at the cash-generating unit level on an annual basis and whenever there is an indication that they may be impaired. In particular, goodwill impairment is based on the lowest level (cash generating unit) to which goodwill can be allocated on a reasonable and consistent basis. A cash generating unit is the smallest aggregate on which the Company, directly or indirectly, evaluates the return on the capital expenditure. If the recoverable amount of a cash generating unit is lower than the carrying amount, goodwill attributed to that cash generating unit is impaired up to that difference; if the carrying amount of goodwill is lower than the amount of the impairment loss, the assets of the cash generating unit are impaired pro-rata on the basis of their carrying amount for the residual difference.

Asset retirement obligations

Obligations to remove tangible equipment and restore land or seabed require significant estimates in calculating the amount of the obligation and determining the amount required to be recorded presently in the Consolidated Financial Statements. Estimating future asset retirement obligations is complex. It requires management to make estimates and judgments with respect to removal obligations that will come to term many years into the future and contracts and regulations are often unclear as to what constitutes removal. In addition, the ultimate financial impact of environmental laws and regulations is not always clearly known as asset removal technologies and costs constantly evolve in the Countries where Eni operates, as do political, environmental, safety and public expectations. The subjectivity of these estimates is also increased by the accounting method used that requires entities to record the fair value of a liability for an asset retirement obligation in the period when it is incurred (typically, at the time the asset is installed at the production location). When provisions are initially recognized, the related fixed assets are increased by an equal corresponding amount. Then the carrying amount of provisions is adjusted to reflect the passage of time and any change in the estimates following the modification of future cash flows and discount rates adopted. The discount rate used to determine the provision is based on managerial judgments.

Business combinations

Accounting for business combinations requires the allocation of the purchase price to the identifiable assets and liabilities of the acquired business at their fair values. Any positive residual difference is recognized as "Goodwill". Any negative residual difference is recognized in the profit and loss account. Management uses all available information to make these fair value measurements and, for major business combinations, engages independent external advisors.

Environmental liabilities

As other oil and gas companies, Eni is subject to numerous EU, national, regional and local environmental laws and regulations concerning its oil and gas operations, production and other activities. They include legislations that implement international conventions or protocols. Environmental costs are recognized when it becomes probable that a liability will be incurred and a reliable estimate can be made of the amount of the obligation. Management, considering the actions already taken, insurance policies obtained to cover environmental risks and provision for risks accrued, does not expect any material adverse effect on Eni s consolidated results of operations and financial position as a result of such laws and regulations. However, there can be no assurance that there will not be a material adverse impact on Eni s consolidated results of operations and financial position due to: (i) the possibility of an unknown contamination; (ii) the results of the ongoing surveys and other possible effects of statements required by applicable laws; (iii) the possible effects of future environmental legislations and rules; (iv) the effects of possible technological changes relating to future remediation; and (v) the possibility of litigation and the difficulty of determining Eni s liability, if any, against other potentially responsible parties with respect to such litigations and the possible reimbursements.

Provisions for employee benefits

Defined benefit plans are evaluated with reference to uncertain events and based upon actuarial assumptions including among others discount rates, expected rates of salary increases, medical cost trends, estimated retirement dates and mortality rates. The significant assumptions used to account for defined benefit plans are determined as follows: (i) discount and inflation rates reflect the rates at which benefits could be effectively settled, taking into account the duration of the obligation. Indicators used in selecting the discount rate include market yields on high quality corporate bonds (or, in the absence of a deep market of these bonds, on the market yields on government bonds). The inflation rates reflect market conditions observed Country by Country; (ii) the future salary levels of the individual employees are determined including an estimate of future changes attributed to general price levels (consistent with inflation rate assumptions), productivity, seniority and promotion; (iii) healthcare cost trend assumptions reflect an estimate of the actual future changes in the cost of the healthcare related benefits provided to the plan participants and are based on past and current healthcare cost trends including healthcare inflation, changes in healthcare utilization and changes in health status of the participants; and (iv) demographic assumptions such as mortality, disability and turnover reflect the best estimate of these future events for individual employees involved. Differences in the amount of the net defined benefit liability (asset), deriving from the remeasurements comprising, among others, changes in the current actuarial assumptions, differences in the previous actuarial assumptions and what has actually occurred and differences in the return on plan assets excluding amounts included in net interest, usually occur. Remeasurements are recognized within statement of comprehensive income for defined benefit plans and within profit and loss account for long-term plans.

Provisions for contingencies
In addition to environmental liabilities, asset retirement obligation and employee benefits, Eni recognizes provisions primarily related to litigations and tax issues. The estimate of these provisions is based on managerial judgments.

Revenue recognition
Revenue recognition in the Engineering & Construction segment is based on the stage of completion of a contract as measured on the cost-to-cost basis applied to contractual revenues. Use of the stage of completion method requires estimates of future gross profit on a contract by contract basis. The future gross profit represents the profit remaining after deducting costs attributable to the contract from revenues provided for in the contract. The estimate of future gross profit is based on a complex estimation process that includes identification of risks related to the geographical region where the activity is carried out, market conditions in that region and any assessment that is necessary to estimate with sufficient precision the total future costs as well as the expected timetable to the end of the contract. Additional revenues, derived from a change in the scope of work, are included in the total amount of revenues when it is probable that the customer will approve the variation and the related amount. Claims deriving from additional costs incurred for reasons attributable to the customer are included in the total amount of revenues when it is probable that the counterparty will accept them.

Revenues from the sale of electricity and gas to retail customers include allocations for the supplies, occurred between the date of the last meters reading and the year end, not yet billed. These estimates are based on the difference between the volumes allocated by the grid managers and the billed volumes, as well as on other factors, considered by the management, which can impact on them.

6 Recent accounting standards

Accounting standards and interpretations issued by the IASB/IFRIC and endorsed by the EU
By Commission Regulation (EU) No. 1256/2012 of December 13, 2012, the amendments to IAS 32 "Financial Instruments: Presentation Offsetting Financial Assets and Financial Liabilities" (hereinafter "amendments to IAS 32") have been endorsed, which state that: (i) in order to set off financial assets and liabilities, the right of set-off must be legally enforceable in all circumstances, such as in the normal course of business, in the event of default or in the event of insolvency or bankruptcy, of one or all of the counterparties; and (ii) in presence of specific characteristics, the gross simultaneous settlement of financial assets and liabilities, that eliminate or result in insignificant credit and liquidity risk, may be considered equivalent to net settlement. The amendments to IAS 32 shall be applied for annual periods beginning on or after January 1, 2014.

By Commission Regulation (EU) No. 1374/2013 of December 19, 2013, the amendments to IAS 36 "Recoverable Amount Disclosures for Non-Financial Assets" have been endorsed (hereinafter "amendments to IAS 36"), which supplements the disclosure of information requiring: (i) the recoverable amount of individual assets or cash generating units for which an impairment loss has been recognized or reversed during the period; and (ii) additional disclosures if recoverable amount is based on fair value less costs of disposal. The amendments to IAS 36 shall be applied for annual periods beginning on or after January 1, 2014.

By Commission Regulation (EU) No. 1375/2013 of December 19, 2013, the amendments to IAS 39 "Financial Instruments: Recognition and Measurement Novation of Derivatives and Continuation of Hedge Accounting" have been endorsed (hereinafter "amendments to IAS 39"). According to these amendments, an entity shall not discontinue hedge accounting in case of novation of the derivative, as a consequence of laws or regulations, which implies that an original counterparty is replaced by a central counterparty. The amendments to IAS 39 shall be applied for annual periods beginning on or after January 1, 2014.

Accounting standards and interpretations issued by the IASB/IFRIC and not yet endorsed by the EU
On November 12, 2009, the IASB issued IFRS 9 "Financial Instruments" (hereinafter "IFRS 9") which changes recognition and measurement criteria of financial assets and their classification in the financial statements. In particular, the new provisions require, interalia, a classification and measurement model of financial assets based exclusively on the following categories: (i) financial assets measured at amortized cost; and (ii) financial assets measured at fair value. The new provisions also require that investments in equity instruments, other than subsidiaries, joint ventures or associates, shall be measured at fair value with effects taken to the profit and loss account. If these investments are not held for trading purposes, subsequent changes in the fair value can be recognized in other comprehensive income, even if dividends are taken to the profit and loss account. Amounts taken to other comprehensive income shall not be subsequently transferred to the profit and loss account even at disposal. In addition, on October 28, 2010, the IASB updated IFRS 9 by incorporating the recognition and measurement criteria of financial liabilities. In particular, the new provisions require, interalia, that if a financial liability is measured at fair value through profit or loss, subsequent changes in the fair value attributable to changes in the own credit risk shall be presented in other comprehensive income; the component related to own credit risk is recognized in profit and loss account if the treatment of the changes in own credit risk would create or enlarge an accounting mismatch. On November 19, 2013, the IASB integrated IFRS 9 with the revised guidance for hedge accounting. The new provisions aim to align hedge accounting more closely with risk management activities and to establish a more principles-based approach to hedge accounting. In particular, the main changes concern: (i) the forward-looking hedge effectiveness assessment rather than bright lines; (ii) the possibility to rebalance the hedging relationship if the risk management objective for that designating hedging relationship remains the same; (iii) the possibility to designate as an hedged item a risk component of a non-financial item, net positions or layer components of items, if specific conditions are met; (iv) the possibility to hedge aggregated exposures, i.e. a combination of a non-derivative exposure and a derivative; and (v) the accounting of time value of purchased options or the forward elements of forward contracts, excluded from the hedge effectiveness assessment, which shall be consistent with the features of the hedged item. Furthermore, in November 2013, the IASB also removed the effective date from IFRS 9 and will decide on the effective date when the entire IFRS 9 project is closer to completion (the previous effective date was January 1, 2015).

On May 20, 2013, the IFRIC issued the interpretation IFRIC 21 "Levies" (hereinafter "IFRIC 21"), which defines the accounting for outflows imposed by governments (e.g. contributions required to operate in a specific market), other than income taxes, fines or penalties. IFRIC 21 sets out criteria for the recognition of the liability, stating that the obligating event that gives rise to the liability, and therefore to its recognition, is the activity that triggers the payment, as identified by the legislation. The provisions of IFRIC 21 shall be applied for annual periods beginning on or after January 1, 2014.

On November 21, 2013, the IASB issued the amendments to IAS 19 "Defined Benefit Plans: Employee Contributions", which allow the recognition of contributions to defined benefit plans from employees or third parties as a reduction of service cost in the period in which the related service is received, provided that the contributions: (i) are set out in the formal conditions of the plan; (ii) are linked to service; and (iii) are independent of number of years of service (e.g. the contributions are a fixed percentage of the employee s salary or a fixed amount throughout the service period or dependent on the employee s age). The amendments shall be applied for annual periods beginning on or after July 1, 2014 (for Eni: 2015 financial statements).

On December 12, 2013, the IASB issued the documents "Annual Improvements to IFRSs 2010-2012 Cycle" and "Annual Improvements to IFRSs 2011-2013 Cycle", which include, basically, technical and editorial changes to existing standards. The amendments to the standards shall be applied for annual periods beginning on or after July 1, 2014 (for Eni: 2015 financial statements).

Eni is currently reviewing these new IFRS to determine the likely impact on the Group s results.

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Current assets

7 Cash and cash equivalents

Cash and cash equivalents of euro 5,431 million (euro 7,936 million at December 31, 2012) included financing receivables originally due within 90 days amounting to euro 3,086 million (euro 5,846 million at December 31, 2012) relating to time deposit with financial institutions having notice greater than a 48-hour period.

Cash amounting to euro 187 million (euro 229 million at December 31, 2012) was restricted due to commitments with the shareholders of Blue Stream Pipeline Co BV for euro 97 million (euro 145 million at December 31, 2012) and judicial investigations and commercial proceedings in the Engineering & Construction segment for euro 90 million (euro 84 million at December 31, 2012). More information about the judicial investigations is disclosed in note 35 Guarantees, commitments and risks - Corruption investigations. The average maturity of financing receivables due within 90 days was 9 days and the average interest rate amounted to 0.3% (0.5% at December 31, 2012).

8 Financial assets held for trading

The breakdown by currency of financial assets held for trading or available for sale is presented below:

	Nominal value (euro million)	Fair value (euro million)	Rating - Moody s	Rating - S&P
Quoted bonds issued by sovereign states				
Sovereign states				
Fixed rate bonds				
Netherlands	150	153	Aaa	AA+
France	140	144	Aa1	AA
Italy	115	116	Baa2	BBB
Belgium	95	99	Aa3	AA
Spain	55	57	Baa3	BBB-
Austria	25	26	Aaa	AA+
Germany	17	17	Aaa	AAA
Denmark	13	13	Aaa	AAA
Poland	10	8	A2	A-
Slovakia	6	7	A2	A
Sweden	5	5	Aaa	AAA
Europe (Supranational Institutions)	99	100	from Aaa to Aa1	from AAA to AA
	730	**745**		
Floating rate bonds				
Italy	667	667	Baa2	BBB
France	100	100	Aa1	AA
Spain	100	100	Baa3	BBB-
Netherlands	56	56	Aaa	AA+
Germany	50	50	Aaa	AAA
Slovakia	1	1	A2	A
Europe (Supranational Institutions)	242	242	from Aaa to Aa1	from AAA to AA
	1,216	**1,216**		
Total quoted bonds issued by sovereign states	**1,946**	**1,961**		
Other bonds				
Fixed rate bonds				
Quoted bonds issued by industrial companies	1,494	1,574	from Aaa to Baa3	from AAA to BBB-
Non-quoted bonds issued by industrial companies	325	325	from P-1 to P-2	from A-1+ to A-2
Quoted bonds issued by financial and insurance companies	377	396	from Aaa to Baa3	from AAA to BBB-
Non-quoted bonds issued by financial and insurance companies	218	218	from P-1 to P-2	from A-1+ to A-2
	2,414	**2,513**		
Floating rate bonds				
Quoted bonds issued by industrial companies	133	133	from Aaa to Baa3	from AAA to BBB-
Quoted bonds issued by financial companies	397	397	from Aaa to Baa3	from AAA to BBB-
	530	**530**		
Total other bonds	**2,944**	**3,043**		
Total other financial assets held for trading	**4,890**	**5,004**		

The breakdown by currency is provided below:

(euro million)	Dec. 31, 2013
Euro	4,954
British pound	37
Swiss franc	13
	5,004

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The fair value was estimated on the basis of market quotations for listed securities and on the basis of appropriate financial valuation methods commonly used for non-quoted securities. More information is disclosed in note 35 Guarantees, commitments and risks.

9 Financial assets available for sale

(euro million)	Dec. 31, 2012	Dec. 31, 2013
Securities held for operating purposes		
Quoted bonds issued by sovereign states	174	165
Quoted securities issued by financial institutions	22	37
Non-quoted securities	5	
	201	**202**
Securities held for non-operating purposes		
Quoted bonds issued by sovereign states	13	
Quoted securities issued by financial institutions	23	7
Non-quoted securities		26
	36	**33**
	237	**235**

The breakdown by currency is provided below:

(euro million)	Dec. 31, 2012	Dec. 31, 2013
Euro	179	173
U.S. dollar	40	58
Indian rupee	18	4
	237	**235**

At December 31, 2013, bonds issued by sovereign states amounted to euro 165 million (euro 187 million at December 31, 2012). A breakdown by Country is presented below:

	Nominal value (euro million)	**Fair value** (euro million)	**Nominal rate of return** (%)	**Maturity date**	**Rating - Moody s**	**Rating - S&P**
Sovereign states						
Fixed rate bonds						
Belgium	27	30	from 2.88 to 4.25	from 2014 to 2021	Aa3	AA
Portugal	22	22	from 3.35 to 4.75	from 2015 to 2019	Ba3	BB
Italy	15	15	from 2.50 to 4.25	2015	Baa2	BBB
Slovakia	14	15	from 3.50 to 4.90	from 2014 to 2017	A2	A
Spain	14	14	from 3.15 to 4.10	from 2014 to 2018	Baa3	BBB-
Ireland	13	14	from 4.40 to 4.50	from 2019 to 2020	Baa3	BBB+
Austria	12	13	from 3.40 to 3.50	from 2014 to 2015	Aaa	AA+

USA	11	11	from 1.75 to 3.13	from 2014 to 2019	Aaa	AA+
Germany	10	10	from 3.25 to 4.25	from 2014 to 2015	Aaa	AAA
Netherlands	6	7	4.00	from 2016 to 2018	Aaa	AA+
France	5	5	4.00	2014	Aa1	AA
Slovenija	5	5	4.38	2014	Ba1	A-
Finland	4	4	from 1.13 to 1.25	from 2015 to 2017	Aaa	AAA
Total	**158**	**165**				

Securities amounting to euro 44 million were issued by financial institutions with a rating ranging from Aaa to B2 (Moody s) and from AAA to BB- (S&P); other listed securities amounted to euro 26 million with a rating of B1 (Moody s) and B- (S&P).

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Securities held for operating purposes of euro 202 million (euro 201 million at December 31, 2012) were designated to hedge the loss provisions of the Group s insurance company Eni Insurance Ltd (euro 196 million at December 31, 2012).

The effects of fair value evaluation of securities are set out below:

(euro million)	Carrying amount at Dec. 31, 2012	Changes recognized in equity	Carrying amount at Dec. 31, 2013
Fair value	7	(1)	6
Deferred tax liabilities	(1)		(1)
Other reserves of shareholders equity	**6**	**(1)**	**5**

The fair value was estimated on the basis of market quotations for quoted securities and on the basis of appropriate financial valuation methods commonly used for non-listed securities.

10 Trade and other receivables

(euro million)	Dec. 31, 2012	Dec. 31, 2013
Trade receivables	**19,958**	**21,212**
Financing receivables:		
- for operating purposes - short term	396	403
- for operating purposes - current portion of long-term receivables	213	481
- for non-operating purposes	1,151	129
	1,760	**1,013**
Other receivables:		
- from disposals	209	88
- other	6,691	6,577
	6,900	**6,665**
	28,618	**28,890**

The increase in trade and other receivables of euro 1,254 million primarily related to the Refining & Marketing segment (euro 656 million) and to the Gas & Power segment (euro 435 million).

Receivables are stated net of the valuation allowance for doubtful accounts of euro 1,877 million (euro 1,635 million at December 31, 2012):

(euro million)	Carrying amount at Dec. 31, 2012	Additions	Deductions	Other changes	Carrying amount at Dec. 31, 2013
Trade receivables	1,055	384	(158)	10	1,291
Financing receivables	6	54		(8)	52
Other receivables	574	36	(54)	(22)	534

1,635	**474**	**(212)**	**(20)**	**1,877**

Additions to the allowance reserve for doubtful trade receivable accounts amounted to euro 384 million (euro 164 million in 2012) and primarily related to the Gas & Power segment (euro 289 million).

Deductions amounted to euro 158 million and related to the Gas & Power segment for euro 98 million.

At the balance sheet date, Eni had in place transactions to transfer to factoring institutions certain trade receivables without recourse for euro 2,533 million, due in 2014 (euro 2,054 million at December 31, 2012, due in 2013). Transferred receivables related to the Refining & Marketing segment (euro 1,389 million), the Gas & Power segment (euro 1,057 million), Versalis (euro 75 million) and Engineering & Construction (euro 12 million). Furthermore, Engineering & Construction transferred certain trade receivables without recourse due in 2014 for euro 222 million through Eni s subsidiary Serfactoring SpA (euro 149 million at December 31, 2012, due in 2013).

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Trade receivables amounting to euro 659 million were due in the Exploration & Production segment and related to hydrocarbons supplies to Egyptian State-owned companies. In order to reduce the outstanding amounts, negotiations and contacts are ongoing with the State companies top management and the Ministerial authorities, in a context of stable relationships with the counterparties.

The ageing of trade and other receivables is presented below:

	Dec. 31, 2012			Dec. 31, 2013		
(euro million)	Trade receivables	Other receivables	Total	Trade receivables	Other receivables	Total
Neither impaired nor past due	**16,836**	**5,829**	**22,665**	**16,625**	**5,432**	**22,057**
Impaired (net of the valuation allowance)	**1,257**	**207**	**1,464**	**1,056**	**172**	**1,228**
Not impaired and past due in the following periods:						
- within 90 days	1,309	83	1,392	1,702	325	2,027
- 3 to 6 months	217	23	240	709	50	759
- 6 to 12 months	159	207	366	606	185	791
- over 12 months	180	551	731	514	501	1,015
	1,865	**864**	**2,729**	**3,531**	**1,061**	**4,592**
	19,958	**6,900**	**26,858**	**21,212**	**6,665**	**27,877**

Trade and other receivables not impaired and past due primarily pertained to high-credit-rating public administrations, state-owned companies and other highly-reliable counterparties for oil, natural gas and chemical products supplies and to retail customers of the Gas & Power segment. The Gas & Power segment recorded a noticeable increase in the amounts past due by retail customers as a consequence of the financial difficulties and the economic slowdown.

Trade receivables included amounts withheld to guarantee certain contract work in progress for euro 209 million (euro 178 million at December 31, 2012).

Trade receivables in currencies other than euro amounted to euro 7,611 million (euro 7,236 million at December 31, 2012).

Financing receivables associated with operating purposes of euro 884 million (euro 609 million at December 31, 2012) included loans granted to unconsolidated subsidiaries, joint ventures and associates to cover capital expenditure requirements for euro 481 million for executing industrial projects (euro 302 million at December 31, 2012) and cash deposits to hedge the loss provision made by Eni Insurance Ltd for euro 321 million (euro 280 million at December 31, 2012). Receivables for financial leasing amounting to euro 16 million at December 31, 2012 were set to zero as a result of the divestment of Finpipe GIE.

Financing receivables not associated with operating activities amounted to euro 129 million (euro 1,151 million at December 31, 2012) and related to: (i) restricted deposits in escrow for euro 92 million of Eni Trading & Shipping SpA (euro 93 million at December 31, 2012) of which euro 82 million with Citigroup Global Markets Ltd, euro 8 million with BNP Paribas and euro 2 million with ABN AMRO relating to derivatives; and (ii) restricted deposits in escrow of receivables of the Engineering & Construction segment for euro 25 million (same amount as of December 31, 2012). The decrease in financing receivables not associated with operating activities of euro 1,022 million related to: (i) the collection from Cassa Depositi e Prestiti for euro 883 million as final installment of the total consideration of euro 3,517 million relating to the divestment of 1,013,619,522 ordinary shares of Snam SpA; and (ii) the collection from Snam SpA of residual receivables for intercompany transactions for euro 141 million.

Financing receivables in currencies other than euro amounted to euro 529 million as of December 31, 2013 (euro 300 million as of December 31, 2012).

Receivables related to divesting activities of euro 88 million (euro 209 million at December 31, 2012) related to the divestment of a 3.25% interest in the Karachaganak project (equal to Eni s 10% interest) to the Kazakh partner KazMunaiGas for euro 79 million. A description of the transaction is reported in note 21 Other non-current receivables.

Other receivables of euro 6,577 million (euro 6,691 million at December 31, 2012) included receivables of euro 575 million relating to the recovery of costs incurred by the Exploration & Production segment undergoing arbitration procedure (euro 481 million at December 31, 2012). Receivables for euro 333 million as of December 31, 2012 were fully collected during 2013 and they related to amounts of gas to be delivered to gas customers who pre-paid the underlying gas volumes in previous years upon activation of the take-or-pay clause.

Other receivables were as follows:

(euro million)	Dec. 31, 2012	Dec. 31, 2013
Receivables originated from divestments	**209**	**88**
Accounts receivable from:		
- joint venture partners in exploration and production	4,343	4,771
- non-financial government entities	17	17
- insurance companies	176	171
- prepayments for services	620	613
- from factoring arrangements	130	121
- other receivables	1,405	884
	6,691	**6,577**
	6,900	**6,665**

Receivables from joint venture partners in exploration and production activities included the share of the liability for defined-benefit plans of euro 264 million (euro 308 million at December 31, 2012), whereby Eni recognized the 100%-liability of all employees of the operated-joint ventures (see note 29 Provisions for employee benefits).

Receivables from factoring arrangements of euro 121 million (euro 130 million at December 31, 2012) related to Serfactoring SpA and consisted of advances for factoring arrangements with recourse and receivables for factoring arrangements without recourse.

Other receivables in currencies other than euro amounted to euro 5,674 million (euro 5,744 million at December 31, 2012).

Because of the short-term maturity and conditions of remuneration of trade receivables, the fair value approximated the carrying amount.

Receivables with related parties are described in note 43 Transactions with related parties.

11 Inventories

	Dec. 31, 2012					Dec. 31, 2013				
(euro million)	Crude oil, gas and petroleum products	Chemical products	Work in progress	Other	Total	Crude oil, gas and petroleum products	Chemical products	Work in progress	Other	Total
Raw and auxiliary materials and consumables	948	190		1,752	2,890	714	209		1,848	2,771
Products being processed and semi-finished products	133	15		1	149	114	14		1	129

Work in progress			1,622		1,622			1,627		1,627
Finished products and goods	2,913	908		77	3,898	2,496	801		93	3,390
Certificates and emission rights				19	19				22	22
	3,994	**1,113**	**1,622**	**1,849**	**8,578**	**3,324**	**1,024**	**1,627**	**1,964**	**7,939**

Contract works in progress for euro 1,627 million (euro 1,622 million at December 31, 2012) are stated net of prepayments for euro 6 million (euro 7 million at December 31, 2012) which corresponded to the amount of the works executed and accepted by customers.

Inventories of euro 105 million were pledged as a guarantee for the payment of storage services.

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Changes in inventories and in the loss provision were as follows:

(euro million)	Carrying amount at the beginning of the year	Changes	New or increased provisions	Deductions	Changes in the scope of consolidation	Currency translation differences	Other changes	Carrying amount at the end of the year
December 31, 2012								
Gross carrying amount	7,837	1,158			(226)	(19)	(1)	8,749
Loss provision	(187)		(58)	64	10	1	(1)	(171)
Net carrying amount	**7,650**	**1,158**	**(58)**	**64**	**(216)**	**(18)**	**(2)**	**8,578**
December 31, 2013								
Gross carrying amount	8,749	(373)			(3)	(181)	(66)	8,126
Loss provision	(171)		(168)	149		3		(187)
Net carrying amount	**8,578**	**(373)**	**(168)**	**149**	**(3)**	**(178)**	**(66)**	**7,939**

Changes of the year amounting to euro 373 million included the decrease of euro 679 million of the Refining & Marketing segment, partially offset by the increase of euro 190 million of the Exploration & Production segment. Additions of euro 168 million and deductions of euro 149 million of the loss provision related to the Refining & Marketing segment for euro 112 million and euro 118 million, respectively.

12 Current tax assets

(euro million)	Dec. 31, 2012	Dec. 31, 2013
Italian subsidiaries	487	555
Foreign subsidiaries	284	247
	771	**802**

Income taxes are described in note 40   Income tax expense.

13 Other current tax assets

(euro million)	Dec. 31, 2012	Dec. 31, 2013
VAT	860	596
Excise and customs duties	200	88
Other taxes and duties	179	151
	1,239	**835**

14 Other current assets

(euro million)	Dec. 31, 2012	Dec. 31, 2013
Fair value of cash flow hedge derivatives	32	14
Fair value of other derivatives	916	718
Other current assets	669	593
	1,617	**1,325**

Derivative fair values were estimated on the basis of market quotations provided by primary info-provider, or alternatively, appropriate valuation methods commonly used in the marketplace.

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Fair value of cash flow hedge derivatives of euro 14 million (euro 32 million at December 31, 2012) related to the hedges entered by the Gas & Power segment. These derivatives were entered into to hedge variability in future cash flows associated to highly probable future sale transactions of gas or electricity or on already contracted sales due to different indexation mechanism of supply costs versus selling prices. A similar scheme applies to exchange rate hedging derivatives. Negative fair value of contracts expiring by 2014 is disclosed in note 26 Other current liabilities; positive and negative fair value of contracts expiring beyond 2014 is disclosed in note 21 Other non-current receivables and in note 31 Other non-current liabilities. The effects of the evaluation at fair value of cash flow hedge derivatives are given in note 33 Shareholders equity and in note 37 Operating expenses. Sale commitments of cash flow hedge derivatives amounted to euro 505 million (purchase and sale commitments of euro 31 million and euro 510 million, respectively, at December 31, 2012). Information on hedged risks and hedging policies is disclosed in note 35 Guarantees, commitments and risks - Risk factors.

The fair value of other derivative contracts is presented below:

	Dec. 31, 2012			Dec. 31, 2013		
(euro million)	**Fair value**	**Purchase commitments**	**Sale commitments**	**Fair value**	**Purchase commitments**	**Sale commitments**
Derivatives on exchange rate						
Interest currency swap	8	44		6	35	
Currency swap	158	3,349	4,597	250	2,320	6,426
Other	3	215	8	1	68	73
	169	**3,608**	**4,605**	**257**	**2,423**	**6,499**
Derivatives on interest rate						
Interest rate swap	1	23		2	36	
	1	**23**		**2**	**36**	
Derivatives on commodities						
Over the counter	713	3,648	9,505	395	6,558	9,231
Future	26	825	9	64	7,666	6,340
Other	7	30	1			
	746	**4,503**	**9,515**	**459**	**14,224**	**15,571**
	916	**8,134**	**14,120**	**718**	**16,683**	**22,070**

Fair value of other derivatives of euro 718 million (euro 916 million at December 31, 2012) consisted of: (i) euro 369 million (euro 564 million at December 31, 2012) of derivatives that failed to meet the formal criteria to be designated as hedges under IFRS because they were entered into in order to manage net exposures to movements in foreign currencies, interest rates or commodity prices. Therefore, such derivatives were not related to specific trade or financing transactions; (ii) euro 344 million (euro 352 million at December 31, 2012) of commodity derivatives entered by the Gas & Power segment for trading purposes and proprietary trading; and (iii) euro 5 million of derivatives related to net settlement agreements, of which euro 7 million of negative fair value hedge derivatives.

Other assets amounted to euro 593 million (euro 669 million at December 31, 2012) and included: (i) prepayments and accrued income for euro 107 million (euro 137 million at December 31, 2012); (ii) pre-paid rentals for euro 63 million (euro 51 million at December 31, 2012); and (iii) pre-paid insurance premiums for euro 53 million (euro 49 million at December 31, 2012). Prepayments that were made to gas suppliers upon triggering the take-or-pay clause provided by the relevant long-term supply arrangements and amounting to euro 129 million as of December 31, 2012 were fully recovered during 2013 through collection of gas.

Transactions with related parties are described in note 43 Transactions with related parties.

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Non-current assets

15 Property, plant and equipment

(euro million)	Net book amount at the beginning of the year	Additions	Depreciation	Impairment losses	Changes in the scope of consolidation	Currency translation differences	Reclassification to assets held for sale	Other changes	Net book amount at the end of the year	Gross book amount at the end of the year	Provisions for depreciation and impairments
December 31, 2012											
Land	792	5			(109)	(8)	(8)	5	677	700	23
Buildings	1,440	60	(109)	(45)	(316)	(3)	(7)	150	1,170	3,181	2,011
Plant and machinery	48,750	1,548	(7,108)	(1,073)	(9,719)	(335)	(304)	8,288	40,047	114,284	74,237
Industrial and commercial equipment	532	74	(121)	(1)	(62)	2		1	425	1,764	1,339
Other assets	832	90	(105)	(75)	(12)	(7)		8	731	2,262	1,531
Tangible assets in progress and advances	22,635	9,490		(406)	(2,207)	(187)	(130)	(7,447)	21,748	23,478	1,730
	74,981	**11,267**	**(7,443)**	**(1,600)**	**(12,425)**	**(538)**	**(449)**	**1,005**	**64,798**	**145,669**	**80,871**
December 31, 2013											
Land	677	10		(8)		(19)	(3)	10	667	693	26
Buildings	1,170	72	(116)	(37)	18	(29)	(7)	197	1,268	3,404	2,136
Plant and machinery	40,047	3,825	(7,071)	(1,847)		(1,570)	(145)	8,334	41,573	121,429	79,856
Industrial and commercial equipment	425	142	(125)	(4)		(19)		31	450	1,865	1,415
Other assets	731	80	(142)	(1)	1	(10)		(294)	365	1,953	1,588
Tangible assets in progress and advances	21,748	6,784		(219)		(996)		(7,877)	19,440	21,424	1,984
	64,798	**10,913**	**(7,454)**	**(2,116)**	**19**	**(2,643)**	**(155)**	**401**	**63,763**	**150,768**	**87,005**

Capital expenditures by segment were the following:

(euro million)	2012	2013
Capital expenditures		
Exploration & Production	8,407	8,754
Gas & Power	147	149
Refining & Marketing	890	664
Versalis	163	311
Engineering & Construction	998	887
Corporate and financial companies	71	130
Other activities - Snam	539	
Other activities	14	21
Elimination of intragroup profits	38	(3)
	11,267	**10,913**

Capital expenditures included capitalized finance expenses of euro 167 million (euro 173 million in 2012, of which euro 26 million relating to discontinued operations) and related to the Exploration & Production segment (euro 124 million), the Refining & Marketing segment (euro 39 million) and the Versalis segment (euro 4 million). The interest rates used for capitalizing finance expense ranged from 2.6% to 5.3% (2.1% and 5.1% at December 31, 2012).

The main depreciation rates used were substantially unchanged from the previous year and ranged as follows:

(%)	
Buildings	2 - 10
Plant and machinery	2 - 10
Industrial and commercial equipment	4 - 33
Other assets	6 - 33

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A breakdown of impairments losses recorded in 2013 and the associated tax effect is provided below:

(euro million)	2012	2013
Impairment losses		
Exploration & Production	547	209
Gas & Power	71	1,200
Refining & Marketing	843	633
Versalis	112	55
Other segments	27	19
	1,600	**2,116**
Tax effects		
Exploration & Production	154	71
Gas & Power	18	355
Refining & Marketing	96	223
Versalis	33	15
Other segments	2	5
	303	**669**
Impairments net of the relevant tax effects		
Exploration & Production	393	138
Gas & Power	53	845
Refining & Marketing	747	410
Versalis	79	40
Other segments	25	14
	1,297	**1,447**

In assessing whether impairment is required, the carrying amounts of property, plant and equipment are compared with their recoverable amounts. The recoverable amount is the higher of an asset s fair value less costs to sell and its value-in-use. Given the nature of Eni s activities, information on asset fair value is usually difficult to obtain unless negotiations with a potential buyer are ongoing. Therefore, the recoverability is verified by using the value-in-use which is calculated by discounting the estimated cash flows arising from the continuing use of an asset. The valuation is carried out for individual asset or for the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets (cash generating unit - CGU). The Group has identified its CGUs: (i) in the Exploration & Production segment, individual oilfields or pools of oilfields whereby technical, economic or contractual features make underlying cash flows interdependent; (ii) in the Gas & Power segment, in addition to the CGUs to which the goodwill arisen from acquisitions was allocated (see note 17 Intangible assets), any of the plants for electricity production have been identified as being individual cash generating units; (iii) in the Refining & Marketing segment, refining plants, Country-specific facilities, retail networks and other distribution channels by Country (ordinary network, high-ways network, and wholesale activities); (iv) in the Versalis segment, production plants by business/plant and related facilities; and (v) in the Engineering & Construction segment, the business units Offshore E&C, Onshore E&C and related facilities and individual rigs for offshore operations.

Recoverable amounts are calculated by discounting the estimated cash flows deriving from the continuing use of the CGUs and, if significant and reasonably determinable, the cash flows deriving from disposal at the end of their useful lives. Cash flows are determined on the basis of the best information available at the moment of the assessment deriving: (i) for the first four years of each projection, from the Company s four-year plan adopted by the top management which provides information on expected oil and gas production volumes, sales volumes, capital expenditures, operating costs and margins and industrial and marketing set-up, as well as trends on the main macroeconomic variables, including inflation, nominal interest rates and exchange rates; (ii) beyond the four-year plan horizon, cash flow projections are estimated based on management s long-term assumptions regarding the main macroeconomic variables (inflation rates, commodity prices, etc.) and along a time horizon which considers the following factors: (a) for the oil&gas CGUs, the residual life of the reserves and the associated projections of operating costs and development expenditures; (b) for the CGUs of the Refining & Marketing segment, Versalis and the power plants, the economical and technical life of the plants and the associated projections of operating costs, expenditures to support plant efficiency, refining and selling margins and, in the case of chemical plants, operating results before depreciation, interest and taxes, with the adoption of normalization assumptions when judged to be necessary; and (c) for the CGUs of the gas market and the Engineering & Construction segment, the perpetuity method of the last-year-plan by using a nominal growth rate ranging from 0% to 2% considering a normalization driver of the perpetuity to reflect any cyclicality observed in the business; and (iii) commodity prices are estimated on the basis of the forward prices prevailing in the marketplace as of the balance sheet date for the first four years of the cash flow projections and the long-term price assumptions adopted by the Company s management for strategic planning purposes and capital budget allocation, considering the supply and demand fundamentals of the main commodities (see Note 3 Summary of significant accounting policies). In particular, the long-term price of oil adopted for assessing the future cash flows of the oil&gas CGUs was $90 per barrel which is adjusted to take into account the expected inflationary rate from 2017 onwards.

Values-in-use are estimated by discounting post-tax cash flows at a rate which corresponds for the Exploration & Production, Refining & Marketing and Versalis to the Company s weighted average cost of capital net of the risk factors attributable to Saipem and the Gas & Power segment which are assessed on a stand alone basis. Then the discount rates are adjusted to factor in risks specific to each country of activity (adjusted post-tax WACC). In 2013, the adjusted post-tax WACC of Eni, which is the driver for calculating each business segment WACC to assess the value-in-use of their respective CGUs, decreased by 40 basis points compared to 2012, primarily as a consequence of the reduced sovereign risk premium incorporated into the yields of ten-year Italian bonds. The other drivers used in determining the cost of capital cost of borrowings to Eni, equity risk, average premium for country risk, debt-to-equity ratio were assessed to record only marginal variations. In 2013, the adjusted WACC rates used for impairment test purposes ranged from 6.4% to 12.2%.

Post-tax cash flows and discount rates were adopted as they resulted in an assessment that substantially approximated a pre-tax assessment.

Impairment losses recognized in the Gas & Power segment of euro 1,200 million were mainly recorded at the electric power plants due to the substantial deterioration in the competitive scenario reflecting structural weakness in demand and as gas-fired cycles were at disadvantage compared to coal-fired production and electricity from renewable sources as a consequence of cyclical reasons (plunging supply costs of coal and abundance of emission certificates) or structural reasons (growth of renewable sources favored by government subsidies). On the basis of these drivers and the relevant projections of unprofitable margins for the production and sale of electricity from combined-cycle power plants, management has impaired the book value of the electric power plants to their lower values-in-use. Other impairments related to gas networks in Hungary due to revisions in the tariff framework and uncertainties concerning the possible future evolution.

Impairment losses recognized in the Refining & Marketing segment of euro 633 million related to refining plants as a consequence of projections of unprofitable margins due to the structural headwinds in the business due to weak demand, excess capacity, increased competitive pressure from product streams coming from Russia, Asia and North America resulting in continuing pressure on selling prices and, in addition, to narrowing differential between the prices of heavy crude qualities versus the market benchmark Brent causing a substantial reduction in the conversion premium. Other minor impairments were recorded to write-off expenditures incurred for safety and plant upgrades at assets which were fully impaired in previous reporting periods. The largest impairment loss was recorded to write-off the book value of a refinery which was tested for impairment using a post-tax discount rate of 7.1%, corresponding to a pre-tax discount rate of 8.8%.

Small impairments were recorded at oil&gas properties in the Exploration & Production segment as a consequence of downward reserve revisions for euro 209 million, substantially offset by reversal of previous years write-off amounting to euro 208 million. The largest impairment losses were recorded at two assets located in Italy which were tested for impairment using a post-tax discount rate of 6.7%, corresponding to a pre-tax discount rate of 4.0% and 6.6%, respectively.

In the Versalis segment impairment losses amounted to euro 55 million and mainly related to the write-off of the book value of marginal production lines which were shut down and to write-off expenditures incurred for safety and plant upgrades at assets which were fully impaired in previous reporting periods.

Foreign currency translation differences of euro 2,643 million primarily related to translations of entities accounts denominated in U.S. dollar (euro 1,725 million), partially offset by translations of entities accounts denominated in Norwegian krone (euro 620 million).

The reclassification to assets held for sale of euro 155 million comprised certain non-strategic assets of the Exploration & Production segment (euro 143 million).

Other changes of euro 401 million related to: (i) the recognition of mineral property in the Exploration & Production segment for euro 276 million in relation to the renegotiation of the contractual terms and the duration extension of some exploration and development licenses as a compensation of the renounce to the deferred tax assets recoverability related to cost incurred and not yet recovered for tax purposes; (ii) asset reversal of impairment for euro 223 million, of which euro 208 million were recorded by the Exploration & Production segment in relation to a gas and condensate field located in Australia due to positive reserve revisions (euro 145 million) and an oil assets in the United States due to improved future production costs (euro 45 million); and (iii) as decrease, the initial recognition of assets and change in estimates of costs for dismantling and site restoration amounting to euro 190 million.

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Unproved mineral interests included in tangible assets in progress and advances are presented below:

(euro million)	Book value at the beginning of the year	Acquisitions	Impairment losses	Reclassification to proved mineral interest	Other changes and currency translation differences	Book value at the end of the year
December 31, 2012						
Congo	1,280			(2)	(24)	1,254
Nigeria	758				(15)	743
Turkmenistan	635		(109)	(1)	(9)	516
Algeria	485			(124)	(6)	355
USA	217		(62)	(51)	42	146
India	48		(26)			22
Other countries	73			(44)		29
	3,496		**(197)**	**(222)**	**(12)**	**3,065**
December 31, 2013						
Congo	1,254			(84)	(51)	1,119
Nigeria	743				(32)	711
Turkmenistan	516			(4)	(22)	490
Algeria	355			(9)	(15)	331
USA	146			(3)	(6)	137
Egypt		45			(1)	44
India	22				(2)	20
Other countries	29		(7)	(6)	(1)	15
	3,065	**45**	**(7)**	**(106)**	**(130)**	**2,867**

Accumulated provisions for impairments amounted to euro 9,885 million (euro 8,050 million at December 31, 2012).

At December 31, 2013, Eni pledged property, plant and equipment for euro 21 million primarily as collateral against certain borrowings (the same amount as of December 31, 2012).

Government grants recorded as a decrease of property, plant and equipment amounted to euro 114 million (euro 132 million at December 31, 2012).

Assets acquired under financial lease agreements amounted to euro 30 million (euro 39 million at December 31, 2012) for service stations of the Refining & Marketing segment.

Contractual commitments related to the purchase of property, plant and equipment are disclosed in note 35 Guarantees, commitments and risks - Liquidity risk.

Property, plant and equipment under concession arrangements are described in note 35 Guarantees, commitments and risks - Asset under concession arrangements.

Property, plant and equipment by segment

(euro million)	Dec. 31, 2012	Dec. 31, 2013
Property, plant and equipment, gross		
Exploration & Production	103,318	107,329
Gas & Power	5,735	5,763
Refining & Marketing	16,805	17,383
Versalis	5,589	5,898
Engineering & Construction	12,621	12,774
Corporate and financial companies	470	589
Other activities	1,617	1,522
Elimination of intragroup profits	(486)	(490)
	145,669	**150,768**
Accumulated depreciation, amortization and impairment losses		
Exploration & Production	55,809	59,195
Gas & Power	2,379	3,794
Refining & Marketing	11,954	12,808
Versalis	4,661	4,793
Engineering & Construction	4,408	4,846
Corporate and financial companies	243	267
Other activities	1,541	1,450
Elimination of intragroup profits	(124)	(148)
	80,871	**87,005**
Property, plant and equipment, net		
Exploration & Production	47,509	48,134
Gas & Power	3,356	1,969
Refining & Marketing	4,851	4,575
Versalis	928	1,105
Engineering & Construction	8,213	7,928
Corporate and financial companies	227	322
Other activities	76	72
Elimination of intragroup profits	(362)	(342)
	64,798	**63,763**

16 Inventory - compulsory stock

Compulsory inventories of euro 2,573 million (euro 2,541 million at December 31, 2012) were primarily held by Italian subsidiaries for euro 2,550 million (euro 2,525 million at December 31, 2012) in accordance with minimum stock requirements of oil and petroleum products set forth by applicable laws.

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17 Intangible assets

(euro million)	Net book value at the beginning of the year	Additions	Amortization	Impairment losses	Changes in the scope of consolidation	Currency translation differences	Other changes	Net book value at the end of the year	Gross book value at the end of the year	Provisions for depreciation and impairments
December 31, 2012										
Intangible assets with finite useful lives										
Exploration expenditures	564	1,871	(1,886)			(10)	9	548	2,653	2,105
Industrial patents and intellectual property rights	157	59	(58)	(1)	(74)	1	54	138	1,206	1,068
Concessions, licenses, trademarks and similar items	848	18	(134)	(1)	(46)		(1)	684	2,522	1,838
Service concession arrangements	3,651	170	(2)		(3,716)		(71)	32	47	15
Intangible assets in progress and advances	244	159		(1)	(57)		(83)	262	268	6
Other intangible assets	1,423	17	(127)	(1,030)	40	7	32	362	2,145	1,783
	6,887	**2,294**	**(2,207)**	**(1,033)**	**(3,853)**	**(2)**	**(60)**	**2,026**	**8,841**	**6,815**
Intangible assets with indefinite useful lives										
Goodwill	4,018			(1,342)	(216)	2	(1)	2,461		
	10,905	**2,294**	**(2,207)**	**(2,375)**	**(4,069)**		**(61)**	**4,487**		
December 31, 2013										
Intangible assets with finite useful lives										
Exploration expenditures	548	1,697	(1,764)			(19)		462	2,712	2,250
Industrial patents and intellectual property rights	138	31	(55)	(2)		(1)	20	131	1,250	1,119
Concessions, licenses, trademarks and similar items	684	17	(115)	(15)			5	576	2,497	1,921
Service concession arrangements	32		(2)				2	32	48	16
Intangible assets in progress and advances	262	124					(26)	360	365	5
Other intangible assets	362	18	(40)	(157)		(1)	(13)	169	2,112	1,943
	2,026	**1,887**	**(1,976)**	**(174)**		**(21)**	**(12)**	**1,730**	**8,984**	**7,254**
Intangible assets with indefinite useful lives										
Goodwill	2,461			(333)	34	(17)	1	2,146		
	4,487	**1,887**	**(1,976)**	**(507)**	**34**	**(38)**	**(11)**	**3,876**		

Capitalized exploration expenditures of euro 462 million (euro 548 million at December 31, 2012) mainly related to the residual book value of license acquisition costs that are amortized on a straight-line basis over the contractual term of the exploration lease or fully written off against profit and loss upon expiration of terms or management s decision to cease any exploration activities. Additions for the year of euro 1,697 million (euro 1,871 million in 2012) included exploration drilling expenditures which are fully capitalized to reflect their investment nature and then entirely amortized for euro 1,509 million (euro 1,650 million in 2012) and license acquisition costs of euro 188 million (euro 221 million in 2012) primarily related to the acquisition of new exploration acreage in Cyprus and Vietnam. Amortizations of euro 1,764 million (euro 1,886 million in 2012) included amortizations of license acquisition costs for euro 255 million (euro 206 million in 2012).

Industrial patents and intellectual property rights of euro 131 million (euro 138 million at December 31, 2012) related to Eni SpA for euro 86 million (euro 89 million at December 31, 2012) and essentially concerned costs for the acquisition and internal development of software and rights for the use of production processes and software.

Concessions, licenses, trademarks and similar items for euro 576 million (euro 684 million at December 31, 2012) primarily comprised transmission rights for natural gas imported from Algeria of euro 523 million (euro 614 million at December 31, 2012) and concessions for mineral exploration of euro 20 million (euro 47 million at December 31, 2012).

Service concession arrangements of euro 32 million primarily pertained to gas distribution activities outside Italy (same amount as of December 31, 2012).

Intangible assets in progress and advances of euro 360 million (euro 262 million at December 31, 2012) related to Eni SpA for euro 267 million (euro 189 million at December 31, 2012) and primarily concerned cost for software development.

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Other intangible assets with finite useful lives of euro 169 million (euro 362 million at December 31, 2012) comprised: (i) royalties for the use of licenses by Versalis SpA amounting to euro 52 million (euro 56 million at December 31, 2012); and (ii) the estimated costs of Eni s social responsibility projects in relation to oil development programs in Val d Agri and in the North Adriatic area connected to mineral rights under concession for euro 35 million (euro 44 million at December 31, 2012) following commitments made with the Basilicata Region, the Emilia Romagna Region and the Province and Municipality of Ravenna. Impairments regarded a loss of euro 157 million (euro 774 million in 2012) recorded on the customer relationship which was recognized upon the business combination of Distrigas NV (now Eni Gas & Power NV) and allocated to the European Market CGU. The driver of the impairments was the continuing competitive pressure in Benelux considering the reduced profitability outlook of the European Market CGU in the light of the structural headwinds of the European gas sector, as described below in the disclosure about goodwill impairments. Furthermore, in 2012, an impairment loss of euro 256 million was recorded to write off the book value of an option to develop an offshore storage facility for commercial modulation of gas in the British North Sea, which was recognized upon the acquisition of Eni Hewett Ltd, driven by continuing weakness in the European gas scenario.

The main depreciation rates used were substantially unchanged from the previous year and ranged as follows:

(%)	
Exploration expenditures	14 - 33
Industrial patents and intellectual property rights	20 - 33
Concessions, licenses, trademarks and similar items	3 - 33
Service concession arrangements	2 - 4
Other intangible assets	4 - 25

Impairment losses of intangible assets with indefinite useful lives (goodwill) amounted to euro 333 million (euro 1,342 million in 2012) and primarily pertained to the Gas & Power segment for euro 329 million (euro 1,342 million in 2012).

Changes in the scope of consolidation of intangible assets with indefinite useful lives (goodwill) of euro 34 million comprised the goodwill recognition made on the purchase price allocation in the business combination of ASA Trade SpA, a company marketing gas in Tuscany, following the 100% acquisition (euro 24 million) and of Est Più SpA, a company marketing gas and electricity in Friuli Venezia Giulia, following the acquisition of a 30% control stake (euro 10 million). In 2012, changes in the scope of consolidation of intangible assets with indefinite useful life (goodwill) of euro 216 million comprised the deconsolidation of Gruppo Snam following the loss of control (euro 314 million) and the inclusion of Nuon Belgium NV (now merged in Eni Gas & Power NV) and Nuon Power Generation Walloon NV (now EniPower Generation NV) following the 100% acquisition (euro 98 million).

The carrying amount of goodwill at the end of the year was euro 2,146 million (euro 2,461 million at December 31, 2012) net of cumulative impairments amounting to euro 2,396 million (euro 2,070 million at December 31, 2012). The breakdown of goodwill by operating segment is as follows:

(euro million)	**Dec. 31, 2012**	**Dec. 31, 2013**
Gas & Power	1,286	991
Engineering & Construction	750	748
Exploration & Production	265	250
Refining & Marketing	160	157
	2,461	**2,146**

Goodwill acquired through business combinations has been allocated to the cash generating units (CGUs) that are expected to benefit from the synergies of the acquisition. The CGUs of the Gas & Power segment are represented by such commercial business units which cash flows are largely interdependent and therefore benefit from acquisition synergies. The recoverable amounts of the CGUs are determined by discounting the future cash flows derived from the continuing use of the CGUs by applying the perpetuity method to assess the terminal value. For the determination of the cash flows see note 15 Property, plant and equipment. In the Gas & Power segment the adjusted WACC discount rates ranged from 6.4% to 10.2% as the WACC of the segment was adjusted to take into account the specific risks of the countries in which the activity takes place. For the Engineering & Construction segment, the rate used was 7.6% and was not adjusted to a specific country risk as the invested capital of the company mainly refers to movable properties. Both the segments registered a reduction of 50-20 basis points due to the lower risk premium for Italy.

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Post-tax cash flows and discount rates were adopted as they resulted in an assessment that substantially approximated a pre-tax assessment.

In the Gas & Power segment goodwill has been allocated to the following CGUs.

Gas & Power segment

(euro million)	Dec. 31, 2012	Dec. 31, 2013
Domestic gas market	767	801
Foreign gas market	519	190
- of which European market	*511*	*188*
	1,286	**991**

Goodwill allocated to the CGU Domestic gas market was recognized upon the buy-out of Italgas SpA minorities in 2003 through a public offering (euro 706 million). This CGU engages in supplying gas to residential customers and small businesses. The increase from 2012 of euro 34 million comprised the acquisition of local companies engaged in retail sale activities. The impairment review performed at the balance sheet date confirmed the recoverability of the carrying amount of the goodwill.

At December 31, 2013, the residual amounts of goodwill allocated to the European gas market CGUs related to the business combinations Altergaz SA (now Eni Gas & Power France SA) in France, Nuon Belgium NV (now merged in Eni Gas & Power NV) in Belgium which is operating in retail sale activities. At December 31, 2012, these CGUs also comprised the goodwill related to gas wholesale and LNG activities acquired through Distrigas NV (now Eni Gas & Power NV) in Belgium and gas wholesale and LNG activities managed directly by the Gas & Power Division of Eni SpA involving large customers (North-West Europe Area France, Germany, Benelux, United Kingdom, Switzerland and Austria). Those wholesale activities benefited of the synergies from the business combination of Distrigas. In performing the impairment review of the recoverability of the carrying amount, management recognized an impairment loss of goodwill amounting to euro 323 million, thus completely writing off the goodwill allocated to these CGUs, considering a reduced profitability outlook due to the structural changes in the economics of the gas business.

The key assumptions adopted in assessing future cash flow projections of the CGUs included marketing margins, forecast sales volumes, the discount rate and the growth rates adopted to determine the terminal value. Information on these drivers was derived from the four-year plan approved by the Company s management which reduced with respect to past reviews the projected returns and cash flows particularly for the assets subject to impairment, driven by expectations of a weak recovery in gas demand due to slow dynamics of European economies and competition from other resources, persistent oversupply and high competitive pressure. These drivers will continue to weigh on spot prices of gas, to which selling prices in the European markets are benchmarked. Management expects that spot prices of gas in the next four-year period will show negative spreads towards the oil-linked costs of gas supplies. In the light of the expected trends in the gas market, management plans to renegotiate the economic terms and flexibility conditions at the Company s main long-term supply contracts. The expected results of these renegotiations are factored in the economic and financial projections of the four-year plan adopted by the management for the gas business. For the assets subject to impairment, management is now assuming in the updated plan with respect to the previous plan: (i) a significant reduction in the long-term average unit marketing margins; (ii) a reduction in sales volumes; (iii) a slightly lower discount rate; and (iv) to assess the terminal value, the long-term growth rate of the perpetuity was set to zero, unchanged from the previous reporting period.

The value-in-use of the CGU European gas market which led to an impairment of the goodwill was assessed by discounting the associated post-tax cash flows at a post-tax rate of 6.6% corresponding to a pre-tax rate of 11.4% (7.3% and 12%, respectively in 2012).

The excess of the recoverable amount of the CGU Domestic gas market over its carrying amount including the allocated portion of goodwill (headroom) amounting to euro 650 million would be reduced to zero under each of the following alternative hypothesis: (i) a decrease of 35% on average in the projected commercial margins; (ii) a decrease of 35% on average in the projected sales volumes; (iii) an increase of 7 percentage points in the discount rate; and (iv) a negative nominal growth rate of 12%. The recoverable amount of the CGU Domestic gas market and the relevant sensitivity analysis were calculated solely on the basis of retail margins.

Engineering & Construction segment

(euro million)	Dec. 31, 2012	Dec. 31, 2013
Offshore E&C	415	415
Onshore E&C	316	314
Other	19	19
	750	**748**

The segment goodwill of euro 748 million was mainly recognized following the acquisition of Bouygues Offshore SA, now Saipem SA (euro 710 million) and allocated to the CGUs Offshore E&C and Onshore E&C. The impairment review performed at the balance sheet date confirmed the recoverability of the carrying amounts of both those CGUs, including the allocated portions of goodwill.

The key assumptions adopted for assessing the recoverable amounts of those two CGUs which exceeded their respective carrying amounts related to operating results, the discount rate and the growth rates of the perpetuity adopted to determine the terminal value. Information on those drivers were collected from the four-year plan approved by the Company s management, while the terminal value was estimated by using a perpetual nominal growth rate of 2% applied to the normalized cash flow of the last year in the four-year plan. Value-in-use of both CGUs was assessed by discounting the associated post-tax cash flows at a post-tax rate of 7.6% (7.8% in 2012) which corresponds to pre-tax rates of 10.0% and 11.0% for the Offshore E&C business unit and the Onshore E&C business unit, respectively (9.9% and 10.7%, respectively in 2012). The headroom of the Offshore E&C business unit of euro 3,471 million would be reduced to zero under each of the following alternative changes in the above mentioned assumptions: (i) a linear decrease of 49% in the operating result over all the years of the plan and the terminal value; (ii) an increase of 5 percentage points in the discount rate; and (iii) negative real growth rate. Changes in each of the assumptions that would cause the headroom of the Onshore E&C business unit to be reduced to zero are greater than those applicable to the Offshore E&C construction CGU described above.

The Exploration & Production and the Refining & Marketing segments tested their goodwill, yielding the following results: (i) in the Exploration & Production segment with goodwill amounting to euro 250 million, management believes that there are no reasonably possible changes in the pricing environment and production/cost profiles that would cause the headroom of the relevant CGUs to be reduced to zero. Goodwill mainly refers to the portion of the purchase price that was not allocated to proved or unproved properties in the business combinations Lasmo, Burren Energy (Congo) and First Calgary. During 2013, goodwill attributed to minor activities in Italy was impaired for an amount of euro 4 million; and (ii) in the Refining & Marketing segment goodwill amounted to euro 157 million at the balance sheet date. Goodwill amounting to euro 137 million pertained to retail networks acquired in previous years in Austria, Czech Republic, Hungary and Slovakia for which profitability expectations have remained unchanged from the previous-year impairment review.

18 Investments

Investments accounted for using the equity method

(euro million)	Book value at the beginning of the year	Additions	Divestments and reimbursements	Share of profit of equity-accounted investments	Share of loss of equity-accounted investments	Deduction for dividends	Changes in the scope of consolidation	Currency translation differences	Other changes	Book value at the end of the year
December 31, 2012										
Investments in unconsolidated entities controlled by Eni	222	6	(11)	37	(4)	(36)	29	(2)	(26)	215
Joint ventures	1,790	185	(1)	244	(95)	(206)	(473)	(12)	13	1,445
Associates	3,012	139	(321)	170	(151)	(129)	(48)	(32)	(847)	1,793
	5,024	**330**	**(333)**	**451**	**(250)**	**(371)**	**(492)**	**(46)**	**(860)**	**3,453**
December 31, 2013										
Investments in unconsolidated entities controlled by Eni	215	9		37	(9)	(24)	(19)	(6)	(2)	201
Joint ventures	1,445	50	(11)	145	(31)	(47)		(94)	(389)	1,068
Associates	1,793	230	(1)	131	(65)	(195)		(73)	64	1,884
	3,453	**289**	**(12)**	**313**	**(105)**	**(266)**	**(19)**	**(173)**	**(327)**	**3,153**

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In 2013, additions of euro 289 million mainly related to capital contributions to joint ventures and associates engaged in the realization of projects in the interest of Eni: Angola LNG Ltd (euro 98 million) which is currently building a liquefaction plant in order to monetize Eni s gas reserves in that Country (Eni s interest in the project being 13.6%); South Stream Transport BV (euro 44 million) which is engaged in the study of feasibility of the South Stream pipeline; PetroJunin SA (euro 43 million) which is developing gas and crude oil fields in Venezuela; and Novamont SpA (euro 41 million) which is engaged in the green chemistry project at the Porto Torres plant.

Divestments and reimbursements of euro 12 million related to the sale of Est Reti Elettriche SpA.

Eni s share of profit of equity-accounted investments and dividend decrease pertained to the following entities:

(euro million)	Dec. 31, 2012			Dec. 31, 2013		
	Share of profit of equity-accounted investments	Deduction for dividends	Eni s interest (%)	Share of profit of equity-accounted investments	Deduction for dividends	Eni s interest (%)
United Gas Derivatives Co	68	60	33.33	56	60	33.33
PetroSucre SA	3		26.00	44	105	26.00
Unión Fenosa Gas SA	149	108	50.00	38		50.00
Unimar Llc	38	78	50.00	30	19	50.00
Eni BTC Ltd	30	31	100.00	25	22	100.00
CARDÓN IV SA	1		50.00	21		50.00
Galp Energia SGPS SA [a]	80	55	24.34			
Other investments	82	39		99	60	
	451	**371**		**313**	**266**	

(a) The investment was accounted for under the equity method until the date of loss of significant influence.

Eni s share of losses of equity-accounted investments related to the following entities:

(euro million)	Dec. 31, 2012		Dec. 31, 2013	
	Share of loss of equity-accounted investments	Eni s interest (%)	Share of loss of equity-accounted investments	Eni s interest (%)
Angola LNG Ltd	35	13.60	42	13.60
Petromar Lda			18	70.00
Société Centrale Electrique du Congo SA			14	20.00
Zagoryanska Petroleum BV	50	60.00	5	60.00
Distribudora de Gas del Centro SA	12	31.35		
EnBW Eni Verwaltungsgesellschaft mbH	82	50.00		
Other investments	71		26	
	250		**105**	

Losses at the equity-accounted investments in Angola LNG Ltd (euro 42 million) related to pre-production expenses and operating costs for commissioning a re-gasification plant.

Other changes of euro 327 million comprised the reclassification to assets held for sale of Artic Russia BV for euro 449 million and, as increase, the reclassification from other investments of Novamont SpA for euro 35 million and the revaluation of Ceská Rafinérská AS for euro 21 million. At the balance sheet date, Eni s interest in Artic Russia was classified as an asset held for sale and measured at fair value due to the loss of joint control over the investee following the satisfaction, before year end, of all conditions precedent to the Sale and Purchase Agreement signed with Gazprom in November 2013. The re-measurement at fair value recorded to profit amounted to euro 1,682 million. The consideration for the disposal was cashed in on January 15, 2014.

List of equity-accounted investments:

(euro million)	Dec. 31, 2012			Dec. 31, 2013		
	Net carrying value	Number of shares held	Eni s interest (%)	Net carrying value	Number of shares held	Eni s interest (%)
Investments in unconsolidated entities controlled by Eni						
Eni BTC Ltd	97	34,000,000	100.00	96	34,000,000	100.00
Other investments (*)	118			105		
	215			**201**		
Joint ventures						
Unión Fenosa Gas SA	507	273,100	50.00	547	273,100	50.00
Eteria Parohis Aeriou Thessalonikis AE	131	116,546,500	49.00	130	116,546,500	49.00
CARDÓN IV SA	73	6,455	50.00	102	8,605	50.00
Unimar Llc	70	50	50.00	76	50	50.00
Eteria Parohis Aeriou Thessalias AE	46	38,445,008	49.00	45	38,445,008	49.00
Petromar Lda	44	1	70.00	22	1	70.00
Artic Russia BV	436	12,000	60.00			
Other investments (*)	138			146		
	1,445			**1,069**		
Associates						
Angola LNG Ltd	1,060	1,279,887,652	13.60	1,067	1,410,127,664	13.60
EnBW Eni Verwaltungsgesellschaft mbH	162	1	50.00	179	1	50.00
PetroSucre SA	242	5,727,800	26.00	173	5,727,800	26.00
United Gas Derivatives Co	106	950,000	33.33	96	950,000	33.33
Novamont SpA				77	6,667	25.00
Fertilizantes Nitrogenados de Oriente CEC	68	1,933,662,121	20.00	68	1,933,565,443	20.00
PetroJunin SA	10	8,640,000	40.00	51	44,424,000	40.00
South Stream Transport BV	14	82,396	20.00	51	82,396	20.00
Rosetti Marino SpA	29	800,000	20.00	32	800,000	20.00
Other investments (*)	102			90		
	1,793			**1,884**		
	3,453			**3,153**		

(*) Each individual amount included herein was lower than euro 25 million.

Carrying amounts of equity-accounted investments included differences between the purchase price of the interest acquired and the book value of the corresponding fraction of net equity amounting to euro 334 million, of which euro 195 million pertained to Unión Fenosa Gas SA (goodwill), euro 78 million to EnBW Eni Verwaltungsgesellschaft mbH (of which goodwill euro 16 million) and euro 43 million to Novamont SpA (goodwill).

The table below sets out the provisions for losses included in the provisions for contingencies of euro 151 million (euro 176 million at December 31, 2012), primarily related to the following equity-accounted investments:

(euro million)	Dec. 31, 2012	Dec. 31, 2013
Industria Siciliana Acido Fosforico - ISAF - SpA (in liquidation)	102	92
VIC CBM Ltd	13	18

Société Centrale Electrique du Congo SA	19	9
Other investments	42	32
	176	**151**

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Other investments

(euro million)	Net book value at the beginning of the year	Additions	Divestments	Valuation at fair value	Currency translation differences	Other changes	Net book value at the end of the year	Gross book value at the end of the year	Accumulated impairment charges
December 31, 2012									
Investments in unconsolidated entities controlled by Eni	3	12					15	16	1
Associates	13		(13)			12	12	12	
Other investments:									
- valued at fair value			(358)	2,528		2,612	4,782	4,782	
- valued at cost	383	49	(145)		(3)	(8)	276	277	1
	399	**61**	**(516)**	**2,528**	**(3)**	**2,616**	**5,085**	**5,087**	**2**
December 31, 2013									
Investments in unconsolidated entities controlled by Eni	15					(1)	14	15	1
Associates	12					1	13	13	
Other investments:									
- valued at fair value	4,782		(2,191)	179			2,770	2,770	
- valued at cost	276	3	(5)		(8)	(36)	230	233	3
	5,085	**3**	**(2,196)**	**179**	**(8)**	**(36)**	**3,027**	**3,031**	**4**

Investments in unconsolidated entities controlled by Eni and associates are stated at cost net of impairment losses. Other investments, for which fair value cannot be reliably determined, were recognized at cost and adjusted for impairment losses.

In 2013, divestments and reimbursements of other investments valued at fair value for euro 2,191 million are stated net of gains on disposals (euro 98 million) and related to the sale of an 11.69% in the share capital of Snam SpA for euro 1,392 million and an 8.19% in the share capital of Galp Energia SGPS SA for euro 799 million.

On May 9, 2013, Eni completed the sale of 395,253,345 shares equal to 11.69% of the share capital of Snam SpA. The offering, carried out through an accelerated book-building aimed at qualified institutional investors, was priced at euro 3.69 per share for a total consideration amounting to euro 1,459 million. The gain amounted to euro 67 million. Following the placement, Eni holds 288,683,602 shares equal to 8.54% of the share capital of Snam which are underlying the euro 1,250 million convertible bond, issued on January 18, 2013, due on January 18, 2016. At December 31, 2013, the retained interest in Snam was stated at fair value for euro 1,174 million, which was determined at a market price of euro 4.07 per share.

On May 31, 2013, Eni completed the placement of 55,452,341 ordinary shares, corresponding to approximately 6.69% of the share capital of Galp Energia SGPS SA. The offering, carried out through an accelerated book-building procedure aimed at qualified institutional investors, was priced at euro 12.22 per share for a total consideration amounting to euro 678 million. The gain amounted to euro 26 million. Furthermore, during 2013, Eni executed private placements and spot sales of Galp s shares equal to 1.50% of the share capital, for a total consideration of euro 152 million, at an average price of euro 12.21 per share, and a gain amounting to euro 5 million. At December 31, 2013, Eni holds 133,945,630 shares equal to 16.15% of Galp s outstanding share capital, of which 8% underlies the exchangeable (approximately euro 1,028 million) bond issued on November 30, 2012 to be due on November 30, 2015 and 8.15% are subject to pre-emptive rights or options exercisable by Amorim Energia. At December 31, 2013, the retained interest in Galp was stated at fair value for euro 1,596 million determined at a market price of euro 11.92

per share.

Fair value adjustment of euro 179 million related to Snam SpA and Galp Energia SGPS SA, of which euro 168 million were reported through profit as income from investments in application of the fair value option provided by IAS 39 in order to eliminate an accounting mismatch derived from the measurement at fair value through profit as a result of the options embedded in the convertible bonds.

In 2012, divestments of euro 516 million related for euro 358 million to the sale through an accelerated book-building procedure with institutional investors of 4% of the share capital of Galp Energia SGPS SA for a total consideration of euro 381 million and a gain on divestment of euro 23 million and to the sale of Interconnector (UK) Ltd for euro 136 million.

In 2012, adjustment at fair value of euro 2,528 million related to the initial recognition and subsequent measurement at market prices of the interests in Snam SpA (euro 1,465 million, of which euro 1,457 million recognized in the profit and loss account and euro 8 million in other comprehensive income) and Galp Energia SGPS SA (euro 1,063 million of which euro 930 million recognized in the profit and loss account and euro 133 million in other comprehensive income) that, as a consequence of the loss of control on Snam following the transaction with Cassa Depositi e Prestiti and the loss of significant influence on Galp following Eni s exit from the shareholders pact, were stated as financial investment in the item Other investments .

The fair values were estimated on the basis of market quotations.

The net carrying amount of other investments of euro 3,027 million (euro 5,085 million at December 31, 2012) was related to the following entities:

(euro million)	Dec. 31, 2012			Dec. 31, 2013		
	Net carrying amount	**Number of shares held**	**Eni s interest (%)**	**Net carrying amount**	**Number of shares held**	**Eni s interest (%)**
Investments in unconsolidated entities controlled by Eni	**15**			**14**		
Associates	**12**			**13**		
Other investments:						
- Galp Energia SGPS SA	2,374	201,839,604	24.34	1,596	133,945,630	16.15
- Snam SpA	2,408	683,936,947	20.23	1,174	288,683,602	8.54
- Nigeria LNG Ltd	90	118,373	10.40	86	118,373	10.40
- Darwin LNG Pty Ltd	65	213,995,164	10.99	58	213,995,164	10.99
- Novamont SpA	35	3,530	15.00			
- other (*)	86			86		
	5,058			**3,000**		
	5,085			**3,027**		

(*) Each individual amount included herein was lower than euro 25 million.

Provisions for losses related to other investments, included within the provisions for contingencies, amounted to euro 12 million (euro 18 million at December 31, 2012).

Other information about investments

The following table summarizes key financial data, net to Eni, as disclosed in the latest available financial statements of unconsolidated entities controlled by Eni, joint ventures and associates:

(euro million)	Dec. 31, 2012			Dec. 31, 2013		
	Unconsolidated entities controlled by Eni	**Joint ventures**	**Associates**	**Unconsolidated entities controlled by Eni**	**Joint ventures**	**Associates**
Total assets	1,604	3,000	3,080	1,633	3,227	2,888
Total liabilities	1,497	1,597	1,294	1,533	2,175	989
Net sales from operations	97	2,274	1,800	101	1,787	1,690
Operating profit	5	346	257	(4)	33	108
Net profit	39	149	170	21	104	77

Total assets and liabilities of unconsolidated controlled entities of euro 1,633 million and euro 1,533 million, respectively (euro 1,604 million and euro 1,497 million at December 31, 2012) pertained to entities acting as sole-operator in the management of oil and gas contracts for euro 1,283 million and euro 1,283 million (euro 1,249 million and euro 1,249 million at December 31, 2012). The residual amount pertained to not significant entities that were excluded from the scope of consolidation for the reasons described in note 2 Principles of consolidation.

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19 Other financial assets

(euro million)	Dec. 31, 2012	Dec. 31, 2013
Financing recivables for operating purposes	844	778
Securities held for operating purposes	69	80
	913	**858**

Financing receivables for operating purposes are stated net of the valuation allowance for doubtful accounts of euro 66 million (euro 30 million at December 31, 2012).

Financing receivables for operating purposes of euro 778 million (euro 844 million at December 31, 2012) primarily pertained to loans granted by the Exploration & Production segment (euro 569 million), the Gas & Power segment (euro 157 million) and the Refining & Marketing segment (euro 4 million). Receivables for financial leasing of euro 13 million at December 31, 2012, were nil at December 31, 2013, as a result of the sale of Finpipe GIE. Financing receivables granted to unconsolidated subsidiaries, joint ventures and associates amounted to euro 320 million.

Financing receivables for operating purposes in currencies other than euro amounted to euro 729 million (euro 785 million at December 31, 2012).

Financing receivables for operating purposes due beyond five years amounted to euro 474 million (euro 525 million at December 31, 2012).

The valuation at fair value of financing receivables of euro 816 million has been estimated based on the present value of expected future cash flows discounted at rates ranging from 0.5% to 4.2% (0.4% and 3.3% at December 31, 2012). The fair value hierarchy is level 2.

Securities of euro 80 million (euro 69 million at December 31, 2012) were designated as held-to-maturity. The following table analyses securities per issuing entity:

	Amortized cost (euro million)	**Nominal value** (euro million)	**Fair value** (euro million)	**Nominal rate of return** (%)	**Maturity date**	**Rating - Moody s**	**Rating - S&P**
Sovereign states							
Fixed rate bonds							
Italy	20	21	22	from 3.50 to 4.75	from 2014 to 2021	Baa2	BBB
Slovenija	8	8	8	from 4.38 to 4.88	2014	Ba1	A-
Spain	3	3	3	3.00	2015	Baa3	BBB-
Belgium	2	2	2	1.25	2018	Aa3	AA
Floating rate bonds							
Italy	15	15	15		from 2014 to 2016	Baa2	BBB
Belgium	7	7	7		2016	Aa3	AA
Spain	7	7	7		2015	Baa3	BBB-
France	5	5	5		2014	Aa1	AA
Slovakia	2	2	2		2015	A2	A
Total sovereign states	**69**	**70**	**71**				
Floating rate bonds							

European Investment Bank	**8**	**8**	**8**	from 2016 to 2018	Aaa	AAA
Other securities issued by Financial Institutions	**3**	**3**	**3**	2014	Baa3	BBB-