ENI SPA
Form 20-F
April 09, 2013

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, 2012

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	**3,634,185,330**

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

* This requirement does not apply to the registrants in respect of this filing.

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 "U.S. $" 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, Petrochemicals and other activities.

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.

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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 share. 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.
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. Balanced conversion capacity of a refinery is a measure of a refinery capacity to process raw materials averaging both capacity at topping and capacity at conversion plants that normally have smaller capacity.
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.

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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.
EPIC	Engineering, Procurement, Installation and Construction.
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

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	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)

(*) In presenting data on production volumes and reserves for total hydrocarbons, natural gas volumes have been converted to oil-equivalent barrels on the basis of a certain equivalency. From July 1, 2012, as part of an ongoing review of the yields at the Company s gas fields currently in production, Eni has updated the conversion rate of gas to 5,492 cubic feet of gas equals 1 barrel of oil (it was 5,550 cubic feet of gas per barrel in previous reporting periods). The effect of this update on production expressed in BOE was 9 kBOE/d for the full year 2012 and the change in the initial reserves balance as of January 1, 2012 amounted to 40 mmBOE. Prior-year converted amounts were left unchanged. Other per-BOE indicators were only marginally affected by the update (e.g. realization prices, costs per BOE) and also negligible was the impact on depreciation and depletion charges. Other oil companies may use different conversion rates.

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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 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, 2008, 2009, 2010, 2011 and 2012. In accordance with the guidelines of IFRS 5, results of Snam SpA and its subsidiaries (Snam) which manage the Italian regulated businesses of gas infrastructures have been reported as discontinued operations due to Eni s plan to divest the business. Eni lost control over the entity in October 2012 as part of a transaction to divest 30% interest less one share in Snam to an Italian entity, Cassa Depositi e Prestiti which is a related party of Eni as both entities are under the common control of the Italian Ministry for Economy and Finance. The divestment took place in accordance to Law No. 27 of March 24, 2012 which mandated the ownership unbundling of Snam from Eni. Prior year data have been reclassified in accordance with guidelines of IFRS 5. The residual interest of Eni in Snam equal to 20.2% of the share capital of the investee as of the balance sheet date was accounted as a financial asset because Eni is forbidden from exercising the underlying voting rights by applicable laws and therefore cannot influence the financial and operating policy decisions of the investee. Furthermore, under applicable rules, Eni is mandated to divest any residual interest in the entity. See Item 5 and Item 7 Related party transactions for more information on the transaction.

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,				
	2008	2009	2010	2011	2012
	(euro million except data per share and per ADR)				
CONSOLIDATED PROFIT STATEMENT DATA					
Net sales from continuing operations	106,978	81,932	96,617	107,690	127,220
Operating profit by segment from continuing operations					
Exploration & Production	16,239	9,120	13,866	15,887	18,451
Gas & Power [1]	2,330	1,914	896	(326)	(3,221)
Refining & Marketing	(988)	(102)	149	(273)	(1,303)
Chemicals	(845)	(675)	(86)	(424)	(683)
Engineering & Construction	1,045	881	1,302	1,422	1,433
Other activities	(466)	(436)	(1,384)	(427)	(302)
Corporate and financial companies	(623)	(420)	(361)	(319)	(345)
Impact of unrealized intragroup profit elimination and other consolidation adjustments [2] [3]	1,690	1,513	1,100	1,263	996
Operating profit from continuing operations	18,382	11,795	15,482	16,803	15,026
Net profit attributable to Eni from continuing operations	8,996	4,488	6,252	6,902	4,198
Net profit (loss) attributable to Eni from discontinued operations [4]	(171)	(121)	66	(42)	3,590
Net profit attributable to Eni	8,825	4,367	6,318	6,860	7,788
Data per ordinary share (euro) [5]					
Operating profit:					
- basic	5.05	3.26	4.27	4.64	4.15
- diluted	5.05	3.26	4.27	4.64	4.15
Net profit attributable to Eni basic and diluted from continuing operations	2.47	1.24	1.72	1.90	1.16
Net profit (loss) attributable to Eni basic and diluted from discontinued operations	(0.05)	(0.03)	0.02	(0.01)	0.99
Net profit attributable to Eni basic and diluted	2.43	1.21	1.74	1.89	2.15
Data per ADR ($) [5] [6]					
Operating profit:					
- basic	14.86	9.08	11.33	12.92	10.67
- diluted	14.86	9.08	11.33	12.92	10.67
Net profit attributable to Eni basic and diluted from continuing operations	7.27	3.45	4.59	5.32	2.98
Net profit (loss) attributable to Eni basic and diluted from discontinued operations	(0.15)	(0.08)	0.05	(0.03)	2.54
Net profit attributable to Eni basic and diluted	7.14	3.36	4.62	5.26	5.53

(1) Following the divestment of a significant stake in Snam and its deconsolidation closed in 2012, results of the G&P business segment include Marketing and International transport activities. To allow a homogeneous comparison, the presentation of prior year data has been modified accordingly.

(2) This item mainly pertained to intra-group sales of commodities, services and capital goods recorded in the assets of the purchasing business segment as of the end of the period.

(3) In the circumstances of discontinued operations, the International Financial Reporting Standards require that the profits earned by continuing and discontinued operations are those deriving from transactions external to the Group. Therefore, profits earned by the discontinued operations, in this case Snam operations, on sales to the continuing operations are eliminated on consolidation from the discontinued operations and attributed to the continuing operations and vice versa. This representation does not indicate the profits earned by continuing and Snam operations, as if they were stand alone entities, for past periods or likely to be earned in future periods. Results attributable to individual segments are not affected by this representation.

(4) In 2012, net profit attributable to Eni from discontinued operations includes post-tax gains on the disposal of a 30% stake and the revaluation of the residual interest in Snam.

(5) 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 2012 is based on the proposal of Eni s management which is submitted to approval at the Annual General Shareholders Meeting scheduled on May 10, 2013.

(6) 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/USD 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 2008 through 2011 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 2012 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 1.08 per ADR) at the Noon Buying Rate recorded on the payment date on October 11, 2012, while the balance of euro 1.08 per ADR was translated at the Noon Buying Rate as recorded on December 31, 2012. The balance dividend for 2012 once the full-year dividend is approved by the Annual General Shareholders Meeting is payable on May 23, 2013 to holders of Eni shares, being the ex-dividend date May 20, while ADRs holders will be paid late on June 7, 2013.

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	As of December 31,				
	2008	2009	2010	2011	2012
	(euro million except data per share and per ADR)				
CONSOLIDATED BALANCE SHEET DATA					
Total assets	116,673	117,529	131,860	142,945	139,641
Short-term and long-term debt	20,837	24,800	27,783	29,597	24,463
Capital stock issued	4,005	4,005	4,005	4,005	4,005
Minority interest	4,074	3,978	4,522	4,921	3,514
Shareholders equity - Eni share	44,436	46,073	51,206	55,472	59,199
Capital expenditures from continuing operations	12,935	12,216	12,450	11,909	12,761
Weighted average number of ordinary shares outstanding (fully diluted - shares million)	3,639	3,622	3,623	3,623	3,623
Dividend per share (euro) [1]	1.30	1.00	1.00	1.04	1.08
Dividend per ADR ($) [1] [2]	3.72	2.91	2.64	2.73	2.82

(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 2012 is based on the proposal of Eni s management which is submitted to approval at the Annual General Shareholders Meeting scheduled on May 10, 2013.

(2) 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/USD 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 2008 through 2011 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 2012 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 1.08 per ADR) at the Noon Buying Rate recorded on the payment date on October 11, 2012, while the balance of euro 1.08 per ADR was translated at the Noon Buying Rate as recorded on December 31, 2012. The balance dividend for 2012 once the full-year dividend is approved by the Annual General Shareholders Meeting is payable on May 23, 2013 to holders of Eni shares, being the ex-dividend date May 20, while ADRs holders will be paid late on June 7, 2013.

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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, 2008, 2009, 2010, 2011 and 2012. Data on production of oil and natural gas and hydrocarbon production sold includes Eni s share of production of affiliates and joint ventures accounted for under the equity method. In presenting data on production volumes and reserves for total hydrocarbons, natural gas volumes have been converted to oil-equivalent barrels on the basis of a certain equivalency. From July 1, 2012, as part of an ongoing review of the yields at the Company s gas fields currently in production, Eni has updated the conversion rate of gas to 5,492 cubic feet of gas equals 1 barrel of oil (it was 5,550 cubic feet of gas per barrel in previous reporting periods). The effect of this update on production expressed in BOE was 9 kBOE/d for the full year 2012 and the change in the initial reserves balance as of January 1, 2012 amounted to 40 mmBOE. Prior-year converted amounts were left unchanged. Other per-BOE indicators were only marginally affected by the update (e.g. realization prices, costs per BOE) and also negligible was the impact on depreciation and depletion charges. Other oil companies may use different conversion rates.

	Year ended December 31,				
	2008	**2009**	**2010**	**2011**	**2012**
Proved reserves of liquids of consolidated subsidiaries at period end (mmBBL)	3,243	3,377	3,415	3,134	3,084
of which developed	*2,009*	*2,001*	*1,951*	*1,850*	*1,762*
Proved reserves of liquids of equity-accounted entities at period end (mmBBL)	142	86	208	300	266
of which developed	*33*	*34*	*52*	*45*	*44*
Proved reserves of natural gas of consolidated subsidiaries at period end (BCF) (1)	17,214	16,262	16,198	15,582	14,190
of which developed	*11,138*	*11,650*	*10,965*	*10,363*	*8,965*
Proved reserves of natural gas of equity-accounted entities at period end (BCF)	3,015	1,588	1,684	4,700	6,767
of which developed	*420*	*234*	*246*	*53*	*424*
Proved reserves of hydrocarbons of consolidated subsidiaries in mmBOE at period end (1)	6,242	6,209	6,332	5,940	5,667
of which developed	*3,948*	*4,030*	*3,926*	*3,716*	*3,394*
Proved reserves of hydrocarbons of equity-accounted entities in mmBOE at period end	666	362	511	1,146	1,499
of which developed	*107*	*74*	*96*	*54*	*122*
Reserves replacement ratio (2)	135	96	125	142	107
Average daily production of liquids (kBBL/d) (3)	1,026	1,007	997	845	882
Average daily production of natural gas available for sale (mmCF/d) (3)	4,143	4,074	4,222	3,763	4,118
Average daily production of hydrocarbons available for sale (kBOE/d) (3)	1,748	1,716	1,757	1,523	1,631
Hydrocarbon production sold (mmBOE)	632.0	622.8	638.0	548.5	598.7
Oil and gas production costs per BOE (4)	7.65	7.41	8.89	10.86	10.82
Profit per barrel of oil equivalent (5)	16.00	8.14	11.91	16.98	15.95

(1) Includes approximately 746, 769, 767 and 767 BCF of natural gas held in storage in Italy as of December 31, 2008, 2009, 2010 and 2011, respectively.

(2) Referred to Eni s subsidiaries and its equity-accounted entities. Consists of: (i) the increase in proved reserves of consolidated subsidiaries attributable to: (a) purchases of minerals in place; (b) revisions of previous estimates; (c) improved recovery; and (d) extensions and discoveries, less sales of minerals in place; divided by (ii) production during the year as set forth in the reserve tables, in each case prepared in accordance with Topic 932. See the unaudited supplemental oil and gas information in "Item 18 Notes to the Consolidated Financial Statements". Expressed as a percentage.

(3) Referred to Eni s subsidiaries and its equity-accounted entities. Natural gas production volumes exclude gas consumed in operations (281, 300, 318, 321 and 383 mmCF/d in 2008, 2009, 2010, 2011 and 2012, respectively).

(4) 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".

(5) 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,				
	2008	2009	2010	2011	2012
Sales of natural gas to third parties (1)	83.69	83.79	75.81	78.16	78.24
Natural gas consumed by Eni (1)	5.63	5.81	6.19	6.21	6.43
Sales of natural gas of affiliates (Eni s share) (1)	8.91	7.95	9.41	9.53	7.92
Total sales and own consumption of natural gas of the Gas & Power segment (1)	98.23	97.55	91.41	93.90	92.59
E&P natural gas sales in Europe and in the Gulf of Mexico (1)	6.00	6.17	5.65	2.86	2.73
Worldwide natural gas sales (1)	104.23	103.72	97.06	96.76	95.32
Electricity sold (2)	29.93	33.96	39.54	40.28	42.58
Refinery throughputs (3)	35.84	34.55	34.80	31.96	30.01
Balanced capacity of wholly-owned refineries (4)	544	554	564	574	767
Retail sales (in Italy and rest of Europe) (3)	12.03	12.02	11.73	11.37	10.87
Number of service stations at period end (in Italy and rest of Europe)	5,956	5,986	6,167	6,287	6,384
Average throughput per service station (in Italy and rest of Europe) (5)	2,502	2,477	2,353	2,206	2,064
Chemical production (3)	7.37	6.52	7.22	6.25	6.09
Engineering & Construction order backlog at period end (6)	19,105	18,730	20,505	20,417	19,739
Employees at period end (units) (7)	71,741	71,461	73,768	72,574	77,838

(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,				
2008	1.60	1.24	1.47	1.39
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

(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 2012	1.31	1.29	1.30
November 2012	1.30	1.27	1.30
December 2012	1.33	1.29	1.32
January 2013	1.36	1.31	1.36
February 2013	1.37	1.31	1.31
March 2013	1.31	1.28	1.28

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 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 5, 2013 was $1.3027 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, we expect 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 and market dynamics. This is likely to increase competition in all our 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 increases, its growth prospects and future results of operations and cash flows may be adversely affected.

In the Gas & Power segment, Eni is facing increasingly strong competition on both the Italian market and the European market due to continuing slowdown in demand and macroeconomic uncertainties in the face of large gas availability on the marketplace which has driven the development of very liquid continental hubs to trade spot gas. Gas supplies to Europe were fuelled by material additions to global LNG availability by upstream producers and large upgrades of existing pipelines and construction of new backbones on several European routes over the latest few years to expand the import capacity from Russia and Algeria. Those developments were compounded by very significant increases in the production of shale gas in the United States which reduced the Country s dependence on imported gas and resulted in diversion of important LNG volumes to Europe. In 2012, those fundamental shifts in market dynamics coupled with a demand downturn triggered intense pricing competition among gas operators which negatively affected profitability. Additionally, gas marketing operators, including Eni, were hit by diverging trends in the cost of gas supplies compared to selling prices. In fact, procurement costs of those operators were mainly indexed to the price of oil and its derivatives as provided by pricing formulas in long-term supply contracts, whereas selling prices were determined on the basis of spot prices at continental hubs which were pressured by weak demands, oversupplies and competition. Those trends resulted in the Company s Gas & Power segment reporting sharply higher operating losses in 2012 (down to euro 3,221 million compared to a loss of euro 326 million in 2011). We believe that the outlook for our gas marketing business will remain weak in the short to medium term as the ongoing trends affecting the sector will take time to be reversed. Management forecasts that a better balance between demand and supply on the European market is unlikely to be achieved before 2014 or 2015. The described trends may negatively affect the Company s future results of operations and cash flows in its natural gas business, also taking into account the Company s contractual obligations to off-take minimum annual volumes of natural gas in accordance to its long-term gas supply contracts that include take-or-pay clauses. See the sector-specific risk section below.

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Eni also faces competition from large, well-established European utilities and other international oil and gas companies in growing its market share and acquiring or retaining clients. A number of large clients, particularly electricity producers and large industrial buyers, in both the domestic market and other European markets have entered the wholesale market of natural 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 from countries with large gas reserves are planning to sell natural gas directly to final clients, which would threaten the market position of companies like Eni which resell gas purchased from producing countries to final customers. These developments may increase the level of competition in both the Italian and other European markets and reduce Eni s expected operating profit and cash flows in the gas business. Finally, following a law decree enacted in March 2012 from the Italian Government to spur competition in the Italian gas sector, management expects that the Company s selling margins will likely come under pressure on sales at the regulated residential and service segments 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 will be achieved by progressively introducing a spot-based indexation mechanism of the cost of gas replacing the current oil-linked formula which mirrors a basket of long-term supply contracts. We expect that similar measures will be introduced by other market regulators in European countries where Eni engages in selling gas to residential clients (see sector-specific risk factors below).

In its domestic electricity business, Eni competes with other producers and traders from Italy or outside of Italy who sell electricity on 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.

In the retail marketing of refined products both in Italy and abroad, Eni competes with third parties (including international oil companies and local operators such as supermarket chains) 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, there is an ongoing pressure from political and administrative entities, including the Italian Antitrust Authority, to increase the level of competition in the retail marketing of fuels. The above mentioned law decree of March 2012 targeted the Italian fuel retail market, by relaxing commercial ties between independent 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. Eni expects developments in this field to further increase pressure on selling margins in the retail marketing of fuels and to reduce opportunities of increasing market share in Italy. Furthermore, the ongoing demand downturn in the Italian fuel market is expected to exacerbate competition among oil companies and other retail operators due to large product availability on the marketplace.

In the Chemical segment, we are facing strong competition from well-established international players and state-owned petrochemical companies, particularly in the most commoditized market segments such as production of basic petrochemicals 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, we expect that petrochemicals producers based in the U.S. will regain market share in the next 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.

Competition in the oil field 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.

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, storage and distribution of petroleum products, production of base chemicals and special products. By their nature the Group s operation expose us 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 our ability to identify and mitigate the risks and hazards inherent to operating in those industries.

In exploration and production, we face 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 risks of 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 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), 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.

In the transportation area, 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 dedicates a great deal of efforts and attention to safety, health, the environment and the prevention of risks; in pursuing compliance with applicable laws and policies; and in responding and learning from unexpected incidents. We seek to minimize these operational risks by carefully designing and building our 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 effectively could result in unexpected incidents, including releases, oil spills, explosions, 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 equipment and other property, all of which could lead to a disruption in operations. Our operations are often conducted in difficult 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. We also face 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 its ability to manage and control such risks. Eni maintains insurance coverage that include coverage for physical damage to our assets, third party liability, workers compensation, pollution and other damage to the environment and other coverage. Our insurance is subject to caps, exclusion and limitation, and there is no assurance that such coverage will adequately protect us against liabilities from all potential consequences and damages. In light of the accident at the Macondo well in the Gulf of Mexico, we may not be able to secure similar coverage for the same costs. Future insurance coverage for our industry could increase in cost and may include higher retentions. Also, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable.

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 to the Group reputation.

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

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

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

We have material operations relating to the exploration and production of hydrocarbons located offshore. In 2012, approximately 52% of our total oil and gas production for the year derived from offshore fields, mainly in Egypt, Libya, Norway, Italy, Angola, the Gulf of Mexico, Congo, UK and Nigeria. Offshore operations in the oil and gas industry are inherently riskier than onshore activities. As the Macondo accident occurred 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. Also 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. In 2012, a gas leak following a well operation occurred at a wellhead platform of the Elgin/Franklin gas field, located in the UK North Sea. The field was operated by an international oil company with Eni holding 21.87% interest in the field. We incurred costs to restart the platform operations and reported a significant loss of production for the year (down by 7 mmBBL). We may also incur environmental liabilities which may arise from the incident.

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 unexpected drilling conditions, pressure or heterogeneities in formations, equipment failures, blow-outs and other forms of accidents, marine risks such as collisions and adverse weather conditions and shortages or delays in the delivery of equipment. Exploration drilling in offshore areas, particularly in deep waters, is generally more challenging and riskier than in onshore areas; the same is true for exploratory activity in remote areas or in challenging environmental conditions in environmentally-sensitive locations such as those we are experiencing in the Barents Sea. 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 significant investments in executing high-risk exploration projects, it is likely that Eni will incur significant exploration and dry hole expenses in future years. Eni plans to explore for oil and gas onshore and offshore. A number of exploration projects are planned in deep and ultra-deep waters or at deep drilling depths, where operations are more challenging and costly than in other areas. Deep water operations generally may require significant time before commercial production of 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, Liberia, Ghana and Gabon), East Africa (Mozambique), the South-East Asia (Indonesia, Vietnam and other locations), Australia, the Barents Sea and the Black Sea. In 2012, the Company spent approximately euro 1.8 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 find 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 conducting several development projects to produce and market hydrocarbon reserves. Certain projects target to develop 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 our 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 goods and services;
the ability to design development projects so as to prevent the occurrence of technical inconvenience;
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 at project execution on the part of international contractors who are awarded project construction activities generally based on the EPC (engineering, procurement, construction) turn key contractual scheme. We believe that this is mainly 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

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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 we have been discovering increasingly important volumes of reserves in remote and harsh locations or environmentally sensitive locations (i.e. the Barents Sea, Alaska, the Jamal Peninsula, the Caspian Sea) where we are 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, delays in the achievement of critical events and production start-up, differences between scheduled and actual timing, as well as cost overruns may adversely affect the economic returns of our development projects. Failure to deliver major projects successfully could negatively impact our results of operations, cash flow and short-term targets of production growth. Finally, developing and marketing hydrocarbons reserves typically requires 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 cost, 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 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 incurred material cost overruns and substantial delay in the scheduling of production start-up at the Kashagan oilfield, where development is ongoing. These negative trends were driven by a number of factors including depreciation of the U.S. dollar versus the euro and other currencies; cost escalation of goods and services required to execute the project; an original underestimation of the costs and complexity to operate in the North Caspian Sea due to lack of benchmarks; design changes to enhance the operability and safety standards of the offshore facilities. The partners of the venture are currently targeting the achievement of the first commercial production by the first half of 2013 in accordance to the updated development plan covering Phase 1 of the field development which was agreed with the Kazakh Authorities in the course of 2012. See "Item 4 Exploration & Production Caspian Sea" for a full description of the material terms of the Kashagan project.

We have also experienced a few delays at a number of development projects located mainly in Algeria, the UK, Angola and Norway. Those delays were attributable to execution issues and delivery of critical equipment reflecting capacity constraints. These events will impact 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 to 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. In 2012, the Company s reserve replacement was negatively affected by lower entitlements in its PSAs and in the economics of marginal productions for an estimated amount of 62 mmBOE, which however did not impair the Company s ability to fully replace reserves produced in the year. See "Item 4 Business overview Exploration & Production" and "Item 5 Management s expectations of operations". 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 reserve without the participation of international oil companies or if our Company fails to establish partnership with national oil companies, our ability to access or develop additional reserves will be limited.

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An inability to replace produced reserves by finding, acquiring and developing additional reserves could adversely impact future production levels and growth prospects. If we are unsuccessful, we may not meet our long-term targets of production growth and reserve replacement, and our 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 Group reserves to fluctuations in future cash flows due to crude oil price movements. 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;

(iii) global and regional dynamics of demand and supply of oil and gas; we believe that the current economic slowdown may have affected global demand for oil. In 2012, gas demand in Europe and Italy fell sharply due to the economic downturn. This trend negatively affected gas prices at our North Sea fields;

(iv) prices and availability of alternative sources of energy. We believe that gas demand in Europe has been impacted by a shift to the use of coal in firing power plants due to cost advantages compared to gas, as well as the rising contribution of renewable energies in satisfying energy requirements. We expect 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.

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) We expect 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, we expect 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 timing of development expenditures;

- whether the prevailing tax rules, other government regulations and contractual conditions will remain the same as on the date estimates are made;
- results of drilling, testing and the actual production performance of Eni s reservoirs after the date of the estimates which may require 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.

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

Many of these factors, assumptions and variables involved in estimating proved reserves are beyond Eni s control and may change over time and impact the estimates of oil and natural gas reserves. Accordingly, the estimated reserves could be significantly different from the quantities of oil and natural gas that will ultimately be recovered. Additionally, 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 44%. The tax rate of the Company s Exploration & Production segment for the fiscal year 2012 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 our oil and gas reserves and gas supplies are located in countries which are politically, socially and economically less stable than OECD countries. Therefore we are exposed to risks of material disruptions to our operations in those less stable countries. As of December 31, 2012, approximately 80% of Eni s proved hydrocarbon reserves were located in such countries and 59% of Eni s supplies of natural gas came from countries outside OECD countries. See "Item 4 Exploration & Production and Gas & Power" for more information about the Group reserve locations and natural gas supplies.

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 with 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 the balance sheet date receivables for euro 481 million relating to cost recovery under a petroleum contract 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 leading to sabotages, acts of violence and incidents. For example, we experienced continuing acts of sabotage and theft in Nigeria which caused significant production losses and negatively affected our results of operations in the Country for the year 2012.

See "Item 4 Exploration & Production Oil and natural gas reserves".

While the occurrence of those events is unpredictable, it is likely that the occurrence of such events could cause Eni to incur material losses or facility disruptions, by this way adversely impacting Eni s results of operations and cash flows.

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

As of end of 2012, approximately 30% of the Company s proved oil and gas reserves were located in North Africa and Middle East. In 2011, several North African and Middle Eastern oil producing countries experienced an extreme level of political instability that has resulted in changes in governments, unrest and violence and consequential economic disruptions. This instability is currently continuing to affect the region. The 2011 situation was particularly serious in Libya where the political instability escalated to turn out into an internal revolution and conflict which caused material disruptions to our operations in the country for a period of eight months. After the end of the conflict in late 2011, Eni was able to restart its all fields, producing facilities and gas exports through the GreenStream pipeline. In the course of 2012, the Company has progressively built up production volumes and achieved a level of approximately 258 kBOE/d on average for the year. However, we were unable to restore the full production plateau at our fields contrary to our initial planning assumptions, due to the complexity of the transition period which the Country is currently undergoing.

We believe that the political outlook in North Africa and Middle East remains an area of risks for our operations, results and strategic development.

Risks associated with our presence in sanction targets

Our activities in Iran could lead to sanctions under relevant U.S. legislation

Eni is currently conducting oil and gas operations in Iran. The legislation and other regulations of the United States 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.

The United States enacted the Iran Sanctions Act of 1996 (as amended, "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"). As a result, in addition to sanctions for knowingly investing in Iran s petroleum sector, parties engaging in business activities in Iran now may be sanctioned under the ISA for knowingly providing to Iran refined petroleum products, and for knowingly providing to Iran goods, services, technology, information or support that could directly and significantly 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 also expanded the menu of sanctions available to the President of the United States by three, from six to nine, and requires the President to impose three of the nine sanctions, as opposed to two of six, if the President has determined that a party has engaged in sanctionable conduct. The new sanctions include a prohibition on transactions in foreign exchange by the sanctioned company, a prohibition of any transfers of credit or payments between, by, through or to any financial institution to the extent the interest of a sanctioned company is involved, and a requirement to "block" or "freeze" any property of the sanctioned company that is subject to the jurisdiction of the United States. Investments in the petroleum sector that commenced prior to the adoption of CISADA appear to remain subject to the pre-amended version of the ISA, except for the mandatory investigation requirements described below, but no definitive guidance has been given. The new sanctions added by CISADA would be available to the President with respect to new investments in the petroleum sector or any other sanctionable activity occurring on or after July 1, 2010. CISADA also adopted measures designed to reduce the President s discretion in enforcement under the ISA, including a requirement for the President to undertake an investigation upon being presented with credible evidence that a person is engaged in sanctionable activity. CISADA also added to the ISA provisions that an investigation need not be initiated, and may be terminated once begun, 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. The President also may waive sanctions, subject to certain conditions and limitations.

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The United States maintains 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, we are 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 our 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 our share price. Even if our activities in and with respect to Iran do not subject us 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.

With regard to the trading of crude oil, the above mentioned measures (in particular, the Iran Threat Reduction and Syrian Human Rights Acts of August 10, 2012, and the National Defense Authorization Acts 2012) provide for a ban on carrying out transactions associated with the purchase of crude oil and a ban on owning, operating or insuring any vessels used to transport Iranian crude. Both bans may be granted a waiver by the U.S. State Department (based on the National Defense Authorization Act for the Fiscal Year 2012) covering the home-country of an entity or the country of destination of the crude oil. A waiver granted to Italy and other EU Member States in March 2012 and lastly renewed on March 13, 2013 for a further 180-day period.

Other sanctions programs have been adopted by various governments and regulators with respect to Iran, including a series of resolutions from the United Nations Security Council, and measures imposed by various countries based on and to implement these United Nations Security Council resolutions. On July 26, 2010, the European Union adopted new restrictive measures regarding Iran (referred to as the "EU measures"). Among other things, the supply of equipment and technology in the following sectors of the oil and gas industry in Iran are prohibited: refining, liquefied natural gas, exploration and production. The prohibition extends to technical assistance, training and financing and financial assistance in connection with such items. Extension of loans or credit to, acquisition of shares in, entry into joint ventures with or other participation in enterprises in Iran (or Iranian owned enterprises outside of Iran) engaged in any of the targeted sectors also is prohibited.

On March 23, 2012 the Council of the European Union enacted regulation prohibiting the import, transport and purchase of Iranian crude oil and petroleum products. The rules allow for the performance of contracts, entered into 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 the last months of 2012, the Council of the European Union adopted new measures providing for additional restrictive measures against Iran including:

- export prohibition on key naval equipment and technology for ship-building, maintenance or refit;
- prohibition in trade in graphite, raw or semi-finished metals, such as aluminum and steel, and software for certain industrial processes;
- ban on the import, purchase or transport of Iranian natural gas;
- prohibitions on the provision of flagging and classification services to Iranian oil tankers and cargo vessels; and
- prohibition on the supply of vessels designed for the transport or storage of Iranian oil and petrochemical products.

The new measures also prohibit transactions between the European Union and Iranian banks and financial institutions, unless an authorization is granted in advance by the relevant Member State and include 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 gas industry companies (the National Iranian Oil Co and its subsidiary operating companies).

The European measures provide 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 Corp 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 (such as the case of Eni service contracts described therein). Under this waiver Eni is allowed to carry out its upstream and oil import activities. In this respect, Eni is in close contact with the competent European authorities in order to obtain the relevant authorizations, certain of which have already been received.

Eni Exploration & Production segment 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 oil fields, and is entitled to recovery of expenditures made, as well as a service fee. The service contracts do not provide for payments to be made by Eni, as contractor, to the Iranian Government (e.g. leasing fees, bonuses, significant amounts of local taxes); all material future cash flows relate to the payment to Eni of its dues. 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. In this respect, we expect to incur operating costs in the range of approximately $10 to $20 million per year over the next few years for contractual support activities and services. In 2012, we incurred $22 million to provide such activities and services.

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.

In 2012, Eni s production in Iran averaged 3 kBOE/d, representing less than 1% of the Eni Group s total production for the year. Eni s entitlement in 2012 represented less than 3% of the overall production from the oil and gas fields that we have developed in Iran. Eni believes that the results from its Iranian exploration and production are immaterial to the Group s results.

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, we will not be regarded as a company of concern for our past Iran related activities.

Between the end of 2011 and the beginning of 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 and 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 among those subject to sanctions.

The new provisions impose, inter alia, sanctions on persons that are determined to have engaged in certain activities in support of Iran s energy and petrochemicals sector that are not specifically targeted by the ISA, as amended by CISADA.

Those activities include:

- the provision of goods, services, technology or support that have a fair market value above certain monetary thresholds and that could directly and significantly contribute to the maintenance or enhancement of Iran s ability to develop its petroleum resources or to the maintenance or expansion of Iran s domestic production of petrochemical products;
- the purchase of petrochemical products from Iran, and the supply of financial, material, technological support for, or goods or services in support of the National Iranian Oil Co (NIOC); and

the participation in a joint oil and gas development venture with Iran, outside Iran, if that venture was established after January 1, 2002.

As discussed above, pursuant to the Darquain service contract, entered into prior to the date of these measures, 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. We do not believe that Eni s activities in Iran (the completion of existing contracts which has already been notified to the U.S. administration when the Special Rule was applied) are sanctionable under the mentioned measures. However, 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 such measures. If sanctions were imposed, their impact could be material and adverse to Eni.

Our Refining & Marketing segment has historically purchased amounts of Iranian crude oil under a term contract with the NIOC and on a spot basis. We purchased 1.63 mmtonnes, 976 ktonnes and 498 ktonnes in 2010, 2011 and 2012, respectively. We paid NIOC $888 million in 2010, $742 million in 2011 and $396 million in 2012, for those purchases.

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In addition, in 2010 we purchased crude oil from international traders and oil companies who, based on bills of loading and shipping documentation available to us, we believe purchased the crude oil from Iranian companies. Purchases were mainly on spot basis. In 2010, we purchased 2.09 mmtonnes of crude oil amounting to $1.1 billion.

Also as a consequence of EU restrictive measures, in June 2012 Eni ceased to import Iranian crude oil with the exception of those volumes necessary to collect outstanding receivables towards Iranian counterparties, as allowed by the European Union sanctions regime.

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

Finally, our 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. Eni plans to suspend all contracts by April 2013 to comply with EU restrictions.

We will continue to monitor closely legislative and other developments in the United States and the European Union in order to determine whether our remaining interests in Iran could subject us to application of either current or future sanctions under the OFAC sanctions, the ISA, the EU Measures or otherwise. If any of our 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 our business, plans to raise financing, sales and reputation.

We have commercial transactions with Syria where we mainly purchase from time to time volumes of crude oil

Our operations in Syria have mainly been limited to transactions carried out by our Refining & Marketing segment with Syrian Petrol Co, an entity controlled by the Syrian Government, for the purchase of crude oil under term purchase contracts or on a spot basis, based on prevailing market conditions.

We purchased 321 ktonnes and 243 ktonnes in 2010 and 2011, respectively. We paid Syrian Petrol Co $163 million in 2010 and $175 million in 2011, for those purchases. No crude oil purchases were made in 2012.

We also purchased small amounts of crude oil from international traders who, based on bills of lading and shipping documentation available to us, we believe purchased those raw materials from Syrian companies.

In 2010, our Engineering & Construction segment was awarded by Dijla Petroleum Co, an affiliate of the Syrian National Oil Co, a contract for the central processing facility to be installed at the Khurbet East oil field, on Block 26.

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 have a limited presence in the Democratic Republic of Congo

In August 2010, we signed a farm-in agreement with the UK-based Surestream Petroleum to acquire the 55% interest and the operatorship in the Ndunda Block in the Democratic Republic of Congo. Currently we are not conducting any activity in this Country.

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 Chemicals 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.

Our 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, our petrochemical operations lack sufficient scale and competitiveness at a number of sites owing also to geographic location and other structural weaknesses. Due to poor industry fundamentals, intense competitive pressures, high feedstock costs, coupled with company-specific factors, our chemical operations incurred substantial operating losses in recent years. In 2012, our chemicals operations reported sharply higher operating losses compared to the year earlier, down to euro 683 million (down by 61%) driven by unprofitable product margins particularly in the basic petrochemicals and polyethylene businesses which were impaired by high oil-based feedstock costs, and lower sales volumes amidst a demand downturn. Looking forward, 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 products 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

In 2012, the Company s gas marketing business reported sharply lower operating losses due to a demand downturn and increasing competitive pressures arising from large gas availability in the marketplace. We expect negative market conditions to affect results and liquidity in 2013 and beyond

The Company s gas marketing business has reported operating losses and negative cash flow in 2012 and 2011 due to a demand downturn and changed competitive dynamics in the European gas sector. Gas demand has been severely hit by the economic slowdown and lower consumption in the thermoelectric sector. The latter trend was affected by an ongoing expansion of renewable sources of electricity and a shift away from gas to the use of coal in firing power plants due to cost advantages. In the face of weak demand, supplies on the marketplace have continued to increase fuelled by pipeline upgrades, growing availability of LNG and the fact that the U.S. have reduced their dependence on LNG imports due to large development of domestic production of shale gas further adding to global LNG supplies. Those 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 latest few years reflecting oversupplies and weak demand. This trend has hit the profitability at European gas marketing operators, including Eni. Those operators procured 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 and margins were squeezed due to a decoupling between spot prices and the oil-linked costs of purchased gas. Adding to the pressure was the circumstance that reduced sales opportunities forced operators to aggressively compete 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 commenced 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. Against this backdrop, our gas marketing business reported sharply higher operating losses down to euro 3,221 million due also to material impairment charges to align the asset book values to their lower values-in-use to reflect a reduced profitability outlook.

Management expects industrial conditions in the gas sector in Italy and Europe to remain unfavorable over the short to the medium term due to continuing market imbalances and strong competition. We forecasts that weak gas demand due to the current economic downturn and uncertainties, the persistence of oversupplies and strong competition will represent risk factors to the profitability outlook of the Company gas marketing business over the next two to three years. Short-term perspectives are anticipated to be highly adverse in Italy where the economic recovery is feeble, the price of gas to industrial and other large clients is likely to align to the pricing level at the continental hubs and finally gas margins are expected to be affected by the liberalization measures enacted by the Italian Government intended to reduce the cost of gas to residential users (see below). We believe 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).

We are seeking to improve our 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

Our 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 in a changed market environment. We are seeking to renegotiate better terms and pricing of our long-term supply contracts in the next future years to align our cost structure to prices prevailing in the marketplace in order to preserve the profitability of our gas operations. If we fail to obtain the planned benefits, our future results and cash flow could be adversely affected. Furthermore, we believe that our results 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 are entitled to fail to arrange renewed contractual terms, both of them may seek an

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arbitration ruling, which increases the uncertainty regarding a final outcome of the renegotiation process. Similarly, we expect that a number of our clients whom we supply to on long-term basis, will request price revisions and other contractual changes.

We expect that current imbalances between demand and supply in the European gas market will persist for sometime

In 2012, gas demand fell by 2% in Europe and by 4% in Italy due to the economic downturn and sharply lower gas consumptions in the thermoelectric sector. Management estimates that gas demand will grow at an average rate of approximately 1.7% in Italy and Europe until 2020. Those estimates have been revised downward from previous management projections to factor in the risks associated with a number of ongoing trends:

- uncertainties and volatility in the macroeconomic cycle; particularly the current downturn in Europe will weigh on the short-term perspectives of a rapid recovery in gas demand;
- growing adoption of consumption patterns and life-styles characterized by wider sensitivity to energy efficiency; and
- EU policies intended to reduce GHG emissions and promote renewable energy sources. For further information about the Company s outlook for gas demand see "Item 4 Gas & Power".

The projected moderate dynamics in demand will not be enough to balance current oversupplies on the marketplace over the next two to three years according to management s estimates. Gas oversupplies have been increasing in recent years as new, large investments to upgrade import pipelines to Europe have come online from Russia and Algeria, and 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. 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 Nord 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 next future as a new LNG plant is expected to start operations at 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.

These developments will be tempered by an expected increase in worldwide gas demand driven by economic growth in China and other emerging economies, a slowdown in additions of new worldwide LNG capacity, and mature field decline in Europe.

Those trends represent risks to the Company s future results of operations and cash flows in its gas business. See "Item 4 Gas & Power" for further information about our long-term expectations on gas demand and supply.

Current, negative trends in gas demands and supplies may impair the Company s ability to fulfill its minimum off-take 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, 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 16 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 off-take 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, up to the minimum contractual quantity. The take-or-pay clause entitles the Company to off-take pre-paid volumes of gas in later years during the period of contract execution. Amounts of cash prepayments and time schedules for off-taking 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 pre-payments range from 10 to 100 percent of the full price.

The right to off-take 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 off-take 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 off-take. Similar considerations apply to ship-or-pay contractual obligations.

Management believes that the current outlook pointing to weak gas demand growth and large gas availability on the marketplace, the possible evolution of sector-specific regulation, as well as strong competitive pressures on 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 triggered 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 2.37 billion and has paid almost the whole of the relevant cash advances.

Considering ongoing market trends and the Company s outlook for its sales volumes which are anticipated to remain stable in 2013 and to increase at a moderate pace in subsequent years, as well as the expected benefit associated with contract renegotiations which may temporarily reduce the annual minimum take and other commercial initiatives, management believes that the Company s exposure to take-or-pay contracts will need continuing monitoring and will continue to give rise to financial risk in future years.

In addition to the financial risk, failure to off-take 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 off-take 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. Finally, the Company expects to incur financing costs considering the cash advances already paid to its suppliers. As a result, the Company s selling margins, results of operations and cash flow may be negatively affected. For further information on the Company s take-or-pay contracts see "Item 4 Gas & Power Purchases".

Eni plans to increase natural gas sales in Europe. If Eni fails to achieve projected growth targets, this could adversely impact future results of operations and liquidity

Over the medium term, Eni plans to increase its natural gas sales in Europe leveraging on its natural gas availability under take-or-pay purchase contracts, availability of transport rights and storage capacity, and widespread commercial presence in Europe. Should Eni fail to increase natural gas sales in Europe as planned due to poor strategy execution or competition, Eni s future growth prospects, results of operations and cash flows might be adversely affected also taking account that Eni might be unable to fulfill its contractual obligations to purchase certain minimum amounts of natural gas based on its take-or-pay purchase contracts currently in force.

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 is entrusted with certain powers in the matters of natural gas pricing. Specifically, the Authority for Electricity and Gas 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 Authority for Electricity and Gas 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. The indexation mechanism set by the Authority for Electricity and Gas basically provides that the cost of the raw material in the pricing formula to the residential sector be indexed to movements in a basket of hydrocarbons. The Authority for Electricity and Gas modified in a few occasions that indexation mechanism by introducing price adjustments to benefit the residential customers.

Finally, the Italian law decree on liberalizations enacted in March 2012 entrusted the AEEG with the task to gradually introduce reference to the price of certain benchmarks quoted at continental hubs in the indexation mechanism of the cost of gas in the pricing of sales to the above mentioned customers. In compliance with the recently enacted law, the AEEG published a consultation document regarding the reform of the gas retail prices proposing, starting from April 2013, 20% of the retail gas price raw material component shall be linked to spot prices (up from current 5%). Starting from October 2013, the raw material component is planned to be 100% spot based; this should be partially offset by the introduction of new tariff components, applicable for the next two thermal years, in order to grant a gradual transition from oil-linked prices to spot market determined prices, to cover the costs of the transition to new supply formulas and to favor an effective renegotiation of long-term contracts for importing gas. Management believes that this development will negatively affect the profitability of the Company sales in the residential market in Italy because we expect that trends in spot prices will be less favorable than the oil-linked cost of gas supplies to the Group, thus limiting our ability to pass cost increases to our clients. This will adversely affect our future results and cash flow.

Recent liberalization measures in the gas storage sector

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 pursuant to Article 14 of Law Decree No. 1/2012. In particular:

- the natural gas storage capacity which becomes available as a result of the decreased amount of strategic storage and of new methods for calculating the modulation storage obligations is assigned to industrial companies and regasifiers; and
- the modulation storage capacity for the needs of "vulnerable customers" is assigned partly with competitive bidding procedures, and partly under existing procedures.

The Italian Government has taken steps to increase competition in the Italian natural gas market. Further regulatory developments are possible in the future which may adversely affect Eni s results of operations and cash flows

The Italian Government has long supported a higher degree of competition in the Italian natural gas market and this may produce significant developments in this area.

In March 2012, a law decree on liberalizations was enacted which established new measures to enhance competition in the Italian natural gas market. Among those measures, there was a provision that required Eni to divest its shareholding in Snam, the Italian dominant player in the field of gas transportation, distribution and storage. The divestiture of a significant stake in Snam was made to an entity controlled by the Italian State, effective October 15, 2012; as part of the transaction Eni lost control over the investee.

Management believes the institutional debate on the degree of competition in the Italian natural gas market and the regulatory activity to be areas of concern and cannot exclude negative impacts deriving from developments on these matters on Eni s future results of operations and cash flows.

For more information on these issues see "Item 4 Regulation of Eni s businesses Gas & Power".

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 petrochemicals activities due to the fact that Eni is the incumbent operator in those markets in Italy and a large European player. See "Item 18 note 34 of the Notes to the Consolidated Financial Statements" for a full description of Eni s main pending antitrust proceedings. 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 regulation

Eni has incurred in the past and will incur material 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, petrochemicals and other Group 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

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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 exposes 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 due to 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 safeguard of the environment, safety on the workplace, health of employees 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.

In addition, growing public concerns in the EU and globally that rising greenhouse gas emissions and climate change may significantly affect the environment and society could adversely affect our businesses, including the possible enactment of stricter regulations that increase our operating costs, affect product sales and reduce profitability. For more discussion about this topic see "Item 4 Environmental regulations".

Furthermore, in the countries where we operate or expect 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, we 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.

Eni has incurred in the past and may incur in the future material environmental liabilities in connection to 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 beliefs that Eni adopts high operational standards to ensure safety of its operations and to protect the environment and health of people and employees, it is possible that incidents like blow-outs, 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.

Environmental laws also require the Company to remediate and clean-up the environmental impacts of prior disposals or releases of chemicals or petroleum substances and pollutants by the Company. Such contingent liabilities may exist at various sites that the Company disposed of, closed or shut down in prior years where the Group products have been produced, processed, stored, distributed or sold, such as chemicals plants, mineral-metallurgic plants, refineries and other facilities. The Company is particularly exposed to the risk of environmental liabilities in Italy where several industrial installations operated by Eni were located which were subsequently divested, closed, liquidated or shut down. 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 claimed that it cannot be held liable for such past contaminations as permitted by applicable regulations in case of declaration rendered by a guiltless owner particularly regulations that enacted into Italian legislation the Directive No. 2004/35/EC plaintiffs and several public administrations have been acting against Eni to claim both the environmental damage and measures to perform additional clean-up and remediation projects in a number of civil and administrative proceedings. Remedial and clean-up activities with respect to the Company s sites are expected to continue in the foreseeable future, impacting our liquidity as with reference to the balance sheet date 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 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 Company s site where a number of public administrations and the Italian Ministry for 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 future environmental restoration and remediation programs are often inherently difficult to estimate.

Legal Proceedings

Eni is 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 the balance sheet date to account for ongoing proceedings, it is possible that in future years Eni may incur significant losses in addition to 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. For more information see disclosure of pending litigation in "Item 18 note 34 of the Notes to the Consolidated Financial Statements".

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 prices 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 slate, which also includes heavy crude qualities, has a lower 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 Chemicals businesses, depends upon the speed at which the prices of gas and products adjust to reflect movements in oil prices.

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, particularly outside Italy, are increasingly benchmarked to gas spot prices quoted at continental hubs. In the current trading environment, spot prices at those hubs are particularly depressed due to oversupply conditions. In 2012, the de-coupling between trends in the oil-linked costs of supplies and spot prices of gas sales was the main driver of the operating loss incurred by our gas marketing business. We expect that such unfavorable trend will continue in 2013 and beyond due to ongoing rising trends in crude oil prices and weak spot prices pressured by sluggish industry fundamentals and competition.

In addition, the Italian Authority for Electricity and Gas 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 we expect a shift to spot prices in the indexation mechanism of the raw material cost which may replace the oil-linked indexation in selling formulas to those customers. See the paragraph "Risks in the Company s gas business" above for more information.

In addition, in light of the changed European gas market environment, Eni has adopted new risk management policies. These policies contemplate the use of derivative contracts to mitigate the exposure of Eni s future cash flows to future changes in gas prices; such exposure had been exacerbated in recent years by the fact that spot prices at European gas hubs have ceased to track the oil prices to which Eni s long-term supply contracts are linked.

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. These contracts may lead to gains as well as losses, which, in each case, may be significant. All derivative contracts that are not entered into for hedging purposes in accordance with IFRS will be accounted through profit and loss, resulting in higher volatility of the gas business operating profit. Please see "Item 5 Financial review Management s expectations of operations" and "Item 11 Quantitative and qualitative disclosures about market risk".

In the Refining & Marketing and Chemicals 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 at 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/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 2012, Eni s refining margins were 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 rising and price differentials may remain compressed.

In this context, management expects that the Company s refining margins will remain at unprofitable levels in 2013 and possibly beyond. In addition, due to a reduced outlook for refining margins and the persistence of weak industry fundamentals, management took substantial impairment charges amounting to euro 846 million before tax to align the book value of the Company s refining plants to their lower values-in-use which impacted 2012 results of operations.

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 2012, Eni s petrochemicals business reported sharply higher operating losses down to euro 683 million due to unprofitable margins on basic petrochemicals products, mainly the margin on cracker, reflecting high oil-based feedstock costs and as demand for petrochemicals commodities plunged due to the economic downturn. A weak demand outlook and rising oil-based feedstock costs will continue to adversely affect Eni s results of operations and liquidity in this business segment in 2013 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. We also may incur unanticipated costs or assume unexpected liabilities and losses in connection with companies or assets we acquire. If the integration and financial risks connected to acquisitions materialize, our 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 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 our 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.

Our crisis management systems may be ineffective

We have 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, we have crisis management plans and capability to deal with emergencies at every level of our operations. If we do not respond or are not seen to respond in an appropriate manner to either an external or internal crisis, our 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 the market risk, including commodity price risk, interest rate risk and foreign currency risk, as well as liquidity risk, and credit risk.

Our 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, we execute 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.

We are engaged in substantial trading and commercial activities in the physical markets. We also use 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. We also use 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 Groups 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 we believe we have 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. For further discussion on this issues see paragraph "Changes in crude oil and natural gas prices may adversely affect Eni s results of operations" above and "Item 11 Quantitative and qualitative disclosures about market 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 at locking in the associated commercial margin. The Group s risk management objectives are to optimize the risk profile of its commercial activities by effectively managing economic margins and safeguarding the value of Eni assets. Also, as part of its risk management activities the Group enters trading activities in order to seek to profit from short-term market opportunities. 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 markets to trade spot gas. To achieve those targets, Eni enters into commodity derivatives transactions in both commodity and financial markets:

(i) to hedge the risk of variability in future cash flows on already contracted or highly probable future sales exposed to commodity risk depending on the circumstance that costs of supplies may be indexed to different market and oil benchmarks compared to the indexing of selling prices. As tight correlation exists between such commodity derivatives transactions and underlying physical contracts, those derivatives are treated in accordance with hedging accounting in compliance with IAS 39, where possible; and
(ii) to pursue speculative purposes such as altering the risk profile associated with a portfolio of contracts (purchase contracts, transport entitlements, storage capacity) or leveraging any pricing differences in the marketplace, seeking to increase margins on existing assets in case of favorable trends in the commodity pricing environment or seeking a potential profit based on expectations of trends in future prices.

Furthermore, the Company is implementing strategies of asset-backed trading in order to maximize the economic value of the flexibilities associated with its assets. Price risks related to asset backed trading activities are mitigated by the natural hedge granted by the assets availability.

These derivative contracts entered to 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 operating profit, particularly in the gas marketing business.

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.

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 we are unable to access the financial markets, including 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 recent years, the Group has experienced a higher than normal level of counterparty failure due to the severity of the economic and financial downturn. In Eni s 2012 Consolidated Financial Statements, Eni accrued an allowance against doubtful accounts amounting to euro 164 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 middle and small businesses and retail customers who are particularly impacted by the current global financial and economic downturn.

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, and 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. See "Item 5 Critical accounting estimates".

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 are 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. A breach of our digital security, either due to intentional actions or due to negligence, could cause serious damage to business operations and, in some circumstances, could result in injury to people, damage to assets, harm to the environment, breaches of regulations, litigation, legal liabilities and reparation costs.

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Our auditor, like all other independent registered public accounting firms operating in Italy, is 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 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 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.

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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, gas marketing operations, power generation, chemicals, oilfield services and engineering industries. Eni has operations in 90 countries and 77,838 employees as of December 31, 2012.

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 43 countries, including Italy, Libya, Egypt, Norway, the UK, Angola, Congo, the United States, Kazakhstan, Russia, Algeria, Australia, Venezuela, Iraq and Mozambique. In 2012, Eni average daily production amounted to 1,631 kBOE/d on an available-for-sale basis. As of December 31, 2012, Eni s total proved reserves amounted to 7,166 mmBOE; proved reserves of subsidiaries totaled 5,667 mmBOE; Eni s share of reserves of equity-accounted entities was 1,499 mmBOE. In 2012, Eni s Exploration & Production segment reported net sales from operations (including inter-segment sales) of euro 35,881 million and operating profit of euro 18,451 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. Following the divestment of a stake of 30% less one share in Snam and deconsolidation of the regulated business of gas infrastructures in Italy effective in 2012, the Gas & Power segment includes only results and activities of the Marketing of gas and the International transport activity. In 2012, Eni s worldwide sales of natural gas amounted to 95.32 BCM, including 2.73 BCM of gas sales made directly by Eni s Exploration & Production segment in Europe and in the United States. Sales in Italy amounted to 34.78 BCM, while sales in European markets were 51.02 BCM that included 2.73 BCM of gas sold to certain importers to Italy.

Eni produces power and steam at a number of operated sites in Italy with a total installed capacity of 5.3 GW as of December 31, 2012. In 2012, sales of power totaled 42.58 TWh. In 2012, Eni s Gas & Power segment reported net sales from operations (including inter-segment sales) of euro 36,200 million and operating loss of euro 3,221 million.

Eni s Refining & Marketing segment engages in crude oil supply, refining and marketing of petroleum products mainly in Italy and in the rest of Europe. In 2012, processed volumes of crude oil and other feedstock amounted to 30.01 mmtonnes and sales of refined products were 48.33 mmtonnes, of which 23.79 mmtonnes in Italy. Retail sales of refined products at operated service stations amounted to 10.87 mmtonnes including Italy and the rest of Europe. In 2012, Eni s retail market share in Italy through its "Eni" and "Agip" branded network of service stations was 31.2%. In 2012, Eni s Refining & Marketing segment reported net sales from operations (including inter-segment sales) of euro 62,656 million and operating loss of euro 1,303 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 this entity are reported within the Gas & Power segment with regard to the results recorded 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.

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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 2012, Eni sold 3.95 mmtonnes of chemical products. In 2012, Eni s Chemical segment reported net sales from operations (including inter-segment sales) of euro 6,418 million and operating loss of euro 683 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 petrochemicals sectors, mainly in the field of performing large EPC (engineering, procurement and construction) 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 2012, Eni s Engineering & Construction segment reported net sales from operations (including intra-group sales) of euro 12,771 million and operating profit of euro 1,433 million.

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

Strategy

Eni s strategy is to grow the Company s main businesses over both the medium and the long term, with improving profitability.

In the Exploration & Production business we plan to grow profitably oil and gas production and to fully replace produced reserves. We intend to boost returns by focusing on delivering the planned projects on time and on budget as well as increasing 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 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 growth 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";

We intend to improve the profitability of our operations in the Gas & Power segment by renegotiating our long-term supply contracts in order to enhance the competitiveness of the Company s gas offer and to mitigate the take-or-pay risk to our liquidity as we manage through the downturn. We plan to retain our market share in Italy and Europe by leveraging the expected improved costs in procurement and logistics and effective commercial actions. The return to profitability will be helped by developing LNG sales in international markets and optimizing margins by means of our trading activities;

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 steep up cost reduction initiatives, energy saving and optimization of plant operations, in order to drive margin expansions. Management plans to implement selective capital projects for upgrading refinery complexity and securing the safety and reliability of our assets. In the marketing business in Italy we plan to enhance profitability through a number of initiatives for 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;

Our Engineering & Construction segment is expected to be adversely impacted by a slowdown in activities due to macroeconomic headwinds and lower profitability at newly acquired orders. However we believe that the business remains well positioned to return to revenue and profitability growth in the medium term leveraging on technologically-advanced assets and competencies in engineering and project management and execution of large and complex oil and gas developments;

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 the ongoing project of converting the Porto Torres site in a modern plant for the manufacture of eco-compatible chemical products and to expand operations in international markets leveraging our technologies and know-how in the field of elastomers.

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 a capital expenditure program amounting to euro 56.8 billion to support continuing organic growth in its segments, mainly the Exploration & Production which will absorb 83% of planned expenditures. That amount includes funds destined to joint venture projects and associates.

For the full year 2013, management expects a capital budget in line with 2012 (in 2012 capital expenditure from continuing operations amounted to euro 12.76 billion, while expenditures incurred in joint venture initiatives and other investments amounted to euro 0.57 billion).

Eni plans to focus on preserving a balanced and well established financial structure. In 2012, following the divestment of a significant stake in Snam, which resulted in the exclusion of Snam s net indebtedness from the Group s consolidated financial statements, and the sale of part of the Group interest in Galp, Eni achieved a stronger balance sheet than in 2011, in line with the Company s new business profile, more exposed to the Exploration & Production business. Looking forward, management will seek 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 90 $/BBL flat in the next four year period and other trading assumptions, as well as the commitments of funding capital expenditure plans and implementing the Company s progressive dividend policy (see "Item 5 Operating and financial review and prospects Management s expectations of operations" and "Item 3 Risk factors").

For fiscal year 2012, management plans to distribute a dividend of euro 1.08 a share subject to approval from the General Shareholders Meeting scheduled on May 10, 2013; the 2012 dividend represents a 4% 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 84.

Significant business and portfolio developments

The significant business and portfolio developments that occurred in 2012 and to date in 2013 were the following:

On October 15, 2012, following the satisfaction of certain conditions precedent, including, in particular, antitrust approval, we finalized the sale to Cassa Depositi e Prestiti SpA ("CDP"), an entity controlled by the Italian Ministry of Economy and Finance, of 1,013,619,522 ordinary shares of Snam SpA, corresponding to 30% less 1 share of the voting shares at a price of euro 3.47 per share, as provided for by the sale and purchase agreement dated June 15, 2012. The total consideration of euro 3,517 million was paid for 75% within the balance sheet date. The remaining 25% amounting to euro 879 million has been paid on February 28, 2013. The exclusion of Snam from the Group s scope of consolidation effective from the last quarter of 2012 resulted in a reduction of financial debt by euro 12.45 billion. Prior to the divestment, Snam had already reimbursed intercompany loans via third-party financing. The transaction implements the provisions of Law No. 27/2012, pursuant to which Eni was mandated to divest the control in Snam in accordance with Legislative Decree No. 93/2011. Including the sale of a further 5% interest in Snam to institutional investors in July 2012, the residual interest of Eni in Snam equal to 20.2% of the share capital was accounted as a financial instrument because Eni cannot exercise the underlying voting rights pursuant to applicable laws and therefore cannot influence the financial and operating policy decisions of Snam. Furthermore, under applicable rules, Eni was mandated to divest any residual interest in Snam following loss of control on the entity. In January 2013, Eni finalized the divestment of a further portion of its interest in Snam with the placement of euro 1,250 million aggregate principal amount of senior, unsecured bonds, exchangeable into ordinary shares of Snam. The bonds have a maturity of 3 years and pay a coupon of 0.625% per year. The bonds will be exchangeable into Snam ordinary shares at an exchange price of euro 4.33 per Snam ordinary share, up to a maximum of approximately 288.7 million ordinary shares of Snam, corresponding to approximately 8.54% of the currently outstanding share capital of Snam.

On July 20, 2012, as part of the agreements signed on March 29, 2012 by Eni and the other relevant shareholders of the Portuguese company Galp Energia, Amorim Energia and Caixa Geral de Depòsitos SA, we sold a 5% interest in Galp Energia to Amorim Energia. The transaction covered 41.5 million shares at the price of euro 14.25 a share, for a total consideration of euro 582 million and a capital gain registered in profit of euro 288 million. Following the sale we ceased to be a party to the existing shareholders agreement governing Galp Energia and our residual interest of 28.34% was stated as a financial instrument.

The exploration campaign carried out in 2012 in the operated Area 4 offshore the Rovuma basin in Mozambique resulted in a significant discovery at the Mamba Gas complex. A total of 7 exploration and appraisal wells were drilled in the area and new, very large exploration opportunities have been identified at the Coral and Mamba North-East prospects, which are independent from Mamba s structure. In December 2012, Eni signed an agreement with Anadarko Petroleum Corp establishing basic principles for the coordinated development of common offshore activities in Area 4, operated by Eni and Area 1, operated by Anadarko. Furthermore, we will jointly plan and construct onshore LNG liquefaction facilities in Northern Mozambique.

On June 28, 2012, the international contractor companies of the final production sharing agreement of the giant Karachaganak gas-condensate field and the Republic of Kazakhstan closed a settlement agreement to all pending claims relating to the recovery of costs incurred to develop the field as well as minor tax issues. The contractor companies divested 10% of their rights and interest in the project to Kazakhstan s KazMunaiGas for a $1 billion net cash consideration ($325 million being Eni s share). From the effective date, Eni s interest in the Karachaganak project has been reduced to 29.25% from the 32.5% previously held.

In 2012, Eni has launched a reorganization to integrate the supply activities of the Gas & Power and Refining & Marketing segments together with the trading, risk management and the wholesale activities of gas and LNG. This integration will allow Eni to capture opportunities from market trends and synergies in commodity risk management.

Eni signed a trilateral agreement with Korea Gas Corp and the Japanese company Chubu Electric Power Co for the sale of 28 loads of LNG corresponding to 1.7 mmtonnes of LNG in the 2013-2017 period.

In October 2012, the Green Refinery project was launched, which targets the conversion of the Venice plant into a "bio-refinery" to produce bio-fuels. The project will involve an estimated investment of approximately euro 100 million leveraging the Ecofining technology developed and licensed by Eni. Bio-fuel production will start from January 1, 2014 and will grow progressively as new facilities enter into operation. The new facilities to be built under the project will be completed in the first half of 2015.

In October 2012, Versalis, Eni s chemical subsidiary, signed agreements to establish two joint ventures with major chemicals operators in South Korea and Malaysia to build and operate facilities for the production of elastomers incorporating Versalis proprietary technologies and know-how. These initiatives are part of Versalis strategy of international expansion in Asian markets with interesting growth prospect where Versalis can leverage on its technological and industrial leadership in elastomers.

In January 2013, Versalis signed a strategic partnership with Yulex for the manufacture of bio-rubber materials for consumer, medical and industrial markets and the construction of an industrial production complex in Southern Europe. The partnership will leverage on Yulex s agronomical competencies and bio-rubber extraction technologies to boost Versalis green products portfolio.

In March 2013, Eni signed a Memorandum of Understanding with Pirelli related to a joint research project for the use of guayule-based natural rubber in tire production. On an exclusivity basis, Versalis will provide an innovative range of guayule-based natural rubber materials, while Pirelli will carry out trial tests to validate the performance of the materials for tire production on industrial basis.

In addition, Eni closed the following transactions:

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

In December 2012, Eni signed an agreement with the Pakistani Authorities and the state oil and gas company OGDCL for the acquisition of 25% and the operatorship of the Indus Block G exploration license. The contractual area is located offshore in ultra-deep waters and covers approximately 7,500 square kilometers.

In August 2012, Eni and its partner Vitol signed a Memorandum of Understanding with the Government of Ghana and Ghana National Petroleum Corp for the development and marketing of gas reserves discovered in the Offshore Cape Three Points Block in the Tano Basin operated by Eni (47.22% interest).

In August 2012, Eni acquired a 25% interest in three blocks offshore Liberia covering an area of 8,145 square kilometers at a maximum water depth of 3,000 meters. The joint venture is operated by another international oil company. This operation marks Eni s entry into Liberia.

In July 2012, Eni was awarded three product sharing contracts by the Government of Kenya. The contracts relate to the L-21, L-23 and L-24 exploration blocks which are located in the deep and ultra-deep waters of the Lamu Basin covering an area of approximately 36,000 square kilometers.

In June and July 2012, Eni acquired the operatorship (50% interest) of three exploration blocks located offshore Vietnam, in the Song Hong and Phu Khanh basins. The three blocks cover approximately 21,000 square kilometers of acreage. These basins are estimated to contain 10% of Vietnam s hydrocarbon resources, mainly gas. 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 June 2012, Eni signed a Share Purchase Agreement with Ukrainian state-owned National Joint Stock Co, Nak Nadra Ukrayny, and Cadogan Petroleum Plc to acquire a 50.01% interest and operatorship of the Ukrainian company Westgasinvest Llc which currently holds subsoil rights to nine unconventional (shale) gas license areas in the Lviv Basin of Ukraine. These licenses cover approximately 3,800 square kilometers of acreage.

In 2012, capital expenditures of continuing operations amounted to euro 12,761 million, of which 89% related to Exploration & Production, Gas & Power and Refining & Marketing businesses, 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 622 million), in particular at the Sannazzaro refinery, as

well as upgrading and rebranding of the refined product retail network (euro 220 million); and (iv) initiatives to improve flexibility of the combined cycle power plants (euro 131 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 businesses, and primarily regarded: (i) the development of oil and gas reserves (euro 7,357 million) deployed mainly in Norway, Kazakhstan, Algeria, 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) 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); and (iii) the upgrading of the fleet used in the Engineering & Construction segment (euro 1,090 million). There were no significant acquisitions in the year.

In 2010, capital expenditures of continuing operations amounted to euro 12,450 million, of which 78% related to Exploration & Production, Gas & Power and Refining & Marketing businesses, and primarily related to: (i) the development of oil and gas reserves (euro 8,578 million) deployed mainly in Egypt, Kazakhstan, Congo, United States and Algeria, and exploration projects (euro 1,012 million) carried out mainly in Angola, Nigeria, United States, Indonesia and Norway; (ii) 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 692 million); and (iii) the upgrading of the fleet used in the Engineering & Construction segment (euro 1,552 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 43 countries, including Italy, Libya, Egypt, Norway, the UK, Angola, Congo, the United States, Kazakhstan, Russia, Algeria, Australia, Venezuela, Iraq and Mozambique. In 2012, Eni average daily production amounted to 1,631 kBOE/d on an available-for-sale basis. As of December 31, 2012, Eni s total proved reserves amounted to 7,166 mmBOE; proved reserves of subsidiaries totaled 5,667 mmBOE; Eni s share of reserves of equity-accounted entities stood to 1,499 mmBOE.

Eni s strategy in its Exploration & Production operations is to pursue profitable production growth leveraging on its strong asset base and market position in a number of core mineral basins. We plan to achieve a production growth rate of more than 4% on average in the 2013-2016 period, based on our long-term Brent price assumptions of 90 $/BBL 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".

Management plans to achieve the target production growth rate by continuing development activities and new project start-ups in the main areas of operations including North Africa, Sub-Saharan Africa, Venezuela, the Barents Sea, the Yamal Peninsula, Kazakhstan, Iraq and the Far East, leveraging Eni s vast knowledge of reservoirs and geological basins, as well as technical and producing synergies. 65% of these new projects have already been sanctioned and management plans to reach 90% by the end of 2013.

Management plans to maximize the production recovery rate at our current fields by counteracting natural field depletion. 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 39.9 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, in particular we plan to start developing the recent gas discovery offshore Mozambique and to progress large and complex projects in the Barents Sea, Nigeria and Indonesia. We are also planning to maintain a prevailing share of projects regulated by production sharing agreements in our portfolio; this will shorten the cost recovery in an environment of high crude oil prices.

Approximately euro 1.8 billion will be spent to execute development projects through equity-accounted entities.

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Exploration projects will attract some euro 5.5 billion to appraise the latest discoveries made by the Company and to support continuing reserve replacement over the next four years. The most important amounts of exploration expenses will be incurred in Angola, Russia, United States, Nigeria, Egypt, Norway and Indonesia; important resources will be dedicated to explore new areas (Kenya, Vietnam, Ukraine and Cyprus) and on unconventional plays. Management plans to achieve a balance between exploration projects in conventional fields versus projects in high risk/high reward basins.

Management believes that in the 2013-2016 period Eni s exploration and production activities will retain significant risks relating to our strong presence in countries which we believe to be politically less stable than OECD Countries and our exposure to complex projects because they are conducted in harsh, remote and environmentally-sensitive areas (Arctic, Gulf of Mexico, deep offshore, etc.). Management plans to mitigate those risks by expanding the geographic reach of our operations and continuing deployment of the Eni cooperation model with host countries based on the commitment to maximize the benefits delivered to local communities by our upstream activities and invest in initiatives that improve socio-economic standards over the long term (access to energy, education, health). Furthermore Eni intends to minimize financial exposure in countries with political risk through well-designed agreements and a selected plan of cash-outs for each project.

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 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. 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 blow-out 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 2013, management plans to spend approximately 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 (SEC) 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.

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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 reserve 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 previous 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. Proved reserves to which Eni is entitled under PSAs 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 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 SEC rules may be less precise. When participating in exploration and production activities operated by others 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, sale 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 PVT (Pressure Volume Temperature) analysis, maps, oil/gas/water production/injection data of wells, reservoir studies, technical analysis relevant to field performance, long-term 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

(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".

to third party evaluators. In 2012, Ryder Scott Co and DeGolyer and MacNaughton provided an independent evaluation of approximately 33% of Eni s total proved reserves at December 31, 2012[4], confirming, as in previous years, the reasonableness of Eni internal evaluation[5].

In the 2010-2012 period, 92% of Eni total proved reserves were subject to an independent evaluation. As at December 31, 2012, the principal Eni properties not subjected to independent evaluation in the last three years were Bouri and Bu Attifel (Libya) and M Boundi (Congo).

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, 2012, 2011 and 2010. Net proved reserves are set out in more detail under the heading "Supplemental oil and gas information" on page F-116.

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, 2010	**724**	**601**	**2,096**	**1,133**	**1,126**	**295**	**230**	**127**	**6,332**
Developed	554	405	1,215	812	543	139	141	117	3,926
Undeveloped	170	196	881	321	583	156	89	10	2,406
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
Equity-accounted entities									
Year ended Dec. 31, 2010			**23**	**28**		**317**	**143**		**511**
Developed			22	5		43	26		96
Undeveloped			1	23		274	117		415
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
Consolidated subsidiaries and equity-accounted entities									
Year ended Dec. 31, 2010	**724**	**601**	**2,119**	**1,161**	**1,126**	**612**	**373**	**127**	**6,843**
Developed	554	405	1,237	817	543	182	167	117	4,022
Undeveloped	170	196	882	344	583	430	206	10	2,821
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

(4) Includes Eni s share of proved reserves of equity-accounted entities.
(5) See "Item 19 Exhibits".

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, 2010	**248**	**349**	**978**	**750**	**788**	**139**	**134**	**29**	**3,415**
Developed	183	207	656	533	251	39	62	20	1,951
Undeveloped	65	142	322	217	537	100	72	9	1,464
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
Equity-accounted entities									
Year ended Dec. 31, 2010			**19**	**6**		**44**	**139**		**208**
Developed			18	4		5	25		52
Undeveloped			1	2		39	114		156
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
Consolidated subsidiaries and equity-accounted entities									
Year ended Dec. 31, 2010	**248**	**349**	**997**	**756**	**788**	**183**	**273**	**29**	**3,623**
Developed	183	207	674	537	251	44	87	20	2,003
Undeveloped	65	142	323	219	537	139	186	9	1,620
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

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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, 2010	**2,644**	**1,401**	**6,207**	**2,127**	**1,874**	**871**	**530**	**544**	**16,198**
Developed	2,061	1,103	3,100	1,550	1,621	560	431	539	10,965
Undeveloped	583	298	3,107	577	253	311	99	5	5,233
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
Equity-accounted entities									
Year ended Dec. 31, 2010			**24**	**118**		**1,520**	**22**		**1,684**
Developed			22	4		214	6		246
Undeveloped			2	114		1,306	16		1,438
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
Consolidated subsidiaries and equity-accounted entities									
Year ended Dec. 31, 2010	**2,644**	**1,401**	**6,231**	**2,245**	**1,874**	**2,391**	**552**	**544**	**17,882**
Developed	2,061	1,103	3,122	1,554	1,621	774	437	539	11,211
Undeveloped	583	298	3,109	691	253	1,617	115	5	6,671
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

Volumes of oil and natural gas applicable to long-term supply agreements with foreign governments in mineral assets where Eni is operator totaled 648 mmBOE as of December 31, 2012 (647 and 683 mmBOE as of December 31, 2011 and 2010, respectively). Said volumes are not included in reserves volumes shown in the table herein.

	Subsidiaries			Equity-accounted entities		
	2010	2011	2012	2010	2011	2012
			(mmBOE)			
Additions to proved reserves	776	176	337	158	644	366
of which purchases and sales of reserves-in-place	*(12)*	*(7)*	*(212)*			*(38)*

Production for the year	(653)	(568)	(610)	(9)	(9)	(13)

	Subsidiaries and equity-accounted entities		
	2010	2011	2012
		(%)	
Proved reserves replacement ratio of subsidiaries and equity-accounted entities	125	142	107

Eni s proved reserves as of December 31, 2012 totaled 7,166 mmBOE (liquids 3,350 mmBBL; natural gas 20,957 BCF) and included the impact of the gas conversion factor update (40 mmBOE). Eni s proved reserves reported an increase of 80 mmBOE, or 1.1%, from December 31, 2011. All sources additions to proved reserves booked in 2012 were 703 mmBOE, of which 337 mmBOE came from Eni s subsidiaries and 366 mmBOE from Eni s share of equity-accounted entities.

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In spite of stable Brent prices at $111 per barrel in 2012 (also $111 in 2011), all sources additions were adversely affected by the unfavorable movements in oil and gas prices on reserves entitlements in certain PSAs and service contracts and in the economics of marginal productions (down 62 mmBOE).

The methods (or technologies) used in the Eni s proved reserves assessment 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 reserves replacement ratio achieved by Eni s subsidiaries and equity-accounted entities was 107% in 2012 (142% in 2011 and 125% in 2010). The ratio did not include the impact associated with adoption of a new conversion factor of natural gas to barrel-of-oil equivalent on the initial balances of proved reserves as of January 1, 2012 estimated at 40 mmBOE as management believes that change did not pertain to the Company s reserve performance for the year. The reserves replacement ratio was calculated by dividing additions to proved reserves 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 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 additions. Management considers the reserves 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 reference hydrocarbon 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 the exploration and production of oil and natural gas - Uncertainties in estimates of oil and natural gas reserves".

The average reserves life index of Eni s proved reserves was 11.5 years as of December 31, 2012 (12.3 years as of December 31, 2011) which included reserves of both subsidiaries and equity-accounted entities.

Eni s subsidiaries

Eni s subsidiaries added 337 mmBOE of proved oil and gas reserves in 2012 (176 mmBOE in 2011). This comprised 266 mmBBL of liquids and 224 BCF of natural gas. Additions to proved reserves derived from: (i) revisions of previous estimates were 321 mmBOE mainly reported in Kazakhstan, Nigeria and Egypt; (ii) extensions, discoveries and others were 200 mmBOE, with major increases booked in Kazakhstan and Angola; (iii) improved recovery were 28 mmBOE mainly reported in Algeria and Nigeria; and (iv) sales of mineral-in-place were 213 mmBOE and resulted from the disposals of Snam (in particular the divestment of 139 mmBOE of gas storage in Italy) and other non-strategic assets as well as the change of the working interest in the Karachaganak field (48 mmBOE).

Eni s share of equity-accounted entities

Eni reported an increase of 366 mmBOE in its share of equity-accounted entities proved oil and gas reserves in 2012 (644 mmBOE in 2011). This comprised mainly 2,100 BCF of natural gas. Additions to proved reserves derived from: (i) revisions of previous estimates were 254 mmBOE mainly reported in Venezuela; (ii) extensions, discoveries and other factors were 149 mmBOE, with major increases booked in Venezuela and Russia; and (iii) sales of mineral-in-place were 38 mmBOE resulting from the divestment of Galp.

Proved undeveloped reserves

Proved undeveloped reserves as of December 31, 2012 totaled 3,650 mmBOE (including the impact of the gas conversion factor update equal to 20 mmBOE). At year end, proved undeveloped reserves of liquids amounted to 1,544 mmBBL, mainly concentrated in Africa and Kazakhstan. Proved undeveloped reserves of natural gas amounted to

11,568 BCF, mainly located in Africa, Russia and Venezuela. Proved undeveloped reserves of consolidated subsidiaries amounted to 1,322 mmBBL of liquids and 5,225 BCF of natural gas.

In 2012, total proved undeveloped reserves increased by 334 mmBOE due to new projects sanctions mainly in Venezuela, Angola and Congo (approximately 438 mmBOE) as well as due to upwards and downwards revisions mainly related to contractual and technical revisions, price effect and portfolio operations.

During 2012, Eni converted 227 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 are related to the following fields/projects: Samburgskoye (Russia), CAFC and MLE (Algeria), Seth (Egypt), Marulk and Tyrihans (Norway), M Boundi (Congo), Clochas (Angola), Zubair (Iraq) and Nikaitchuq (USA).

In 2012, capital expenditure amounted to approximately euro 1.9 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 1.1 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 (approximately 0.6 BBOE) where development activities are progressing and production start-up is targeted by the end of the first half 2013. Such PUD reserves will be produced within the limits of the oil processing capacity that is planned to be available at end of the ongoing developing phase (Phase 1 or Experimental Program). For more details regarding this project please refer to part 1, Item 4, page 54, where the project is disclosed; (ii) some Libyan gas fields (0.27 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 projects including a gas asset located in Siberia where development activities are progressing and we are targeting production start-up in the short-to-medium term (see also our discussion under the "Item 3 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 431 mmBOE from producing assets located mainly in Australia, Egypt, Libya, Nigeria, Norway and Russia.

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 72% of delivery commitments.

Eni has met all contractual delivery commitments as of December 31, 2012.

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.*

In 2012, oil and natural gas production available for sale averaged 1,631 kBOE/d (1,523 kBOE/d in 2011). Production for the year expressed in barrel-of-oil equivalent was calculated assuming a natural gas conversion factor which was updated to 5,492 CF of gas equaling 1 barrel of oil. On a comparable basis, i.e. when excluding the effect of updating the gas conversion factor, production reported an increase of 7% for the full year. The performance was driven by an ongoing recovery in Libyan production and continuing field start-up and ramp-up mainly in Russia and Australia as well as increased production in Iraq. These positives were partly offset by the temporary shutdown of the Elgin/Franklin field (Eni s interest 21.87%) in the UK due to a gas leak, losses in Nigeria due to force majeure and mature field declines.

Liquids production (882 kBBL/d) increased by 37 kBBL/d, or 4.4%, due the ramp-up of Libyan production and growth registered mainly in: (i) Australia, due to the ramp-up of the Kitan field (Eni operator with a 40% interest); and (ii) Iraq, due to increased production at the Zubair field (Eni s interest 32.8%). Production declined in the United Kingdom and Nigeria following the driver described above and mature field declines, mainly in Angola.

Natural gas production (4,118 mmCF/d) increased by 355 mmCF/d, or 9.4%. The performance was driven by the ramp-up of Libyan production and start-ups in: (i) Samburgskoye field (Eni s interest 29.4%) in Russia, by means of start-up of the first and the second train with an expected production level of 95 kBOE/d (28 kBOE/d net to Eni); and (ii) Seth field in the Ras el Barr offshore concession (Eni s interest 50%) in Egypt. Production plateau is expected at approximately 170 mmCF/d (approximately 11 kBOE/d net to Eni). These positives were partly offset by lower production in the United Kingdom and facilities downtime in the United States.

Oil and gas production sold amounted to 598.7 mmBOE. The 23.9 mmBOE difference over production (622.6 mmBOE) reflected mainly volumes of natural gas consumed in operations (25.5 mmBOE).

Approximately 57% of liquids production sold (325.4 mmBBL) was destined to Eni s Refining & Marketing Division (of which 25% was processed in Eni s refineries); about 29% of natural gas production sold (1,501 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

	2010		2011		2012	
(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	61		64		63	
Rest of Europe	121		120		95	
North Africa	297	4	204	5	267	4
Sub-Saharan Africa	318	3	275	3	245	2
Kazakhstan	65		64		61	
Rest of Asia	47	1	33	1	41	3
Americas	60	11	55	10	72	11

Australia and Oceania	9		11		18	
	978	**19**	**826**	**19**	**862**	**20**

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NATURAL GAS PRODUCTION AVAILABLE FOR SALE [1]

	2010		2011		2012	
(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		648		667	
Rest of Europe	517		498		421	
North Africa	1,556	3	1,165	4	1,589	3
Sub-Saharan Africa	365		422		444	
Kazakhstan	221		212		202	
Rest of Asia	412	24	378	20	355	68
Americas	385		323		273	
Australia and Oceania	91		93		96	
	4,195	**27**	**3,739**	**24**	**4,047**	**71**

(1) It excludes production volumes of natural gas consumed in operations. Said volumes were 383, 321 and 318 mmCF/d in 2012, 2011 and 2010, respectively.

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 78 kBOE/d, 28 kBOE/d and 105 kBOE/d in 2012, 2011 and 2010, 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	America	Australia and Oceania	Total
2010									
Consolidated subsidiaries									
Oil and condensate, per BBL	72.19	67.26	70.96	78.23	66.74	75.20	72.84	73.00	**72.95**
Natural gas, per kCF	8.71	7.40	6.87	1.87	0.49	4.35	4.70	7.40	**6.01**
Average production cost, per BOE	9.42	9.42	5.63	15.19	6.40	5.62	8.15	9.75	**8.89**
Equity-accounted entities									
Oil and condensates, per BBL			16.09	77.78		57.05	71.70		**58.86**
Natural gas, per kCF						9.87			**8.73**
Average production cost, per BOE			13.53	9.73		5.05	27.78		**17.45**
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**

Development activities

In 2012, a total of 351 development wells were drilled (163.6 of which represented Eni s share) as compared to 407 development wells drilled in 2011 (186.1 of which represented Eni s share) and 399 development wells drilled in 2010 (178 of which represented Eni s share). The drilling of 109 wells (36.9 of which represented Eni s share) is currently underway.

The table below summarizes the number of the Company s net interests 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, 2012. 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	
	2010		2011		2012		2012	
(units)	Productive	Dry	Productive	Dry	Productive	Dry	Gross	Net
Italy	23.9	1.0	25.3		18.0	1.0	3.0	2.6
Rest of Europe	2.9	0.2	3.3	0.3	2.9	0.6	9.0	1.8
North Africa	44.3	0.3	55.9	1.1	46.0	1.6	19.0	8.1
Sub-Saharan Africa	28.0	2.5	28.2	1.0	27.4	0.3	19.0	4.4
Kazakhstan	1.8		1.3		1.4		16.0	2.9
Rest of Asia	41.7	1.8	39.2	2.5	41.2	0.1	36.0	14.2
Americas	27.6	0.5	27.6		23.1		7.0	2.9
Australia and Oceania	1.5		0.4					
Total including equity-accounted entities	**171.7**	**6.3**	**181.2**	**4.9**	**160.0**	**3.6**	**109.0**	**36.9**

Exploration activities

In 2012, a total of 60 new exploratory wells were drilled (34.1 of which represented Eni s share), which includes drilled exploratory wells that have been suspended pending further evaluation, as compared to 56 exploratory wells drilled in 2011 (28 of which represented Eni s share) and 47 exploratory wells drilled in 2010 (23.8 of which represented Eni s share).

The overall commercial success rate was 40% (40.8% net to Eni) as compared to 42% (38.6% net to Eni) and 41% (39% net to Eni) in 2011 and 2010, 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, 2012. 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 [(a)]	
	2010		2011		2012		2012	
(units)	Productive	Dry	Productive	Dry	Productive	Dry	Gross	Net

Italy		0.5			1.0		5.0	3.4
Rest of Europe	1.7	1.1	0.3	0.7	1.0	1.0	19.0	7.2
North Africa	9.3	8.1	6.2	3.4	6.3	11.3	17.0	11.7
Sub-Saharan Africa	2.3	4.7	0.6	2.6	4.5	5.1	57.0	24.2
Kazakhstan						0.8	8.0	1.4
Rest of Asia	1.0	2.8	0.2	7.6	0.5	0.6	27.0	11.2
Americas		6.3	2.5			0.1	10.0	2.4
Australia and Oceania	1.0	0.4		1.4		0.4	1.0	0.5
Total including equity-accounted entities	**15.3**	**23.9**	**9.8**	**15.7**	**13.3**	**19.3**	**144.0**	**62.0**

(a) Includes temporary suspended wells pending further evaluation.

Oil and gas properties, operations and acreage

As of December 31, 2012, Eni s mineral right portfolio consisted of 1,072 exclusive or shared rights for exploration and development in 43 countries on five continents for a total acreage of 251,170 square kilometers net to Eni of which developed acreage of 40,939 square kilometers and undeveloped acreage of 210,231 square kilometers.

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In 2012, changes in total net acreage mainly derived from: (i) new leases mainly in China, Indonesia, Kenya, Liberia, Norway, Pakistan and Ukraine for a total acreage of approximately 51,000 square kilometers; (ii) partial relinquishment or interest reduction in Algeria, Australia, Egypt, India, Ireland, Nigeria, Timor Leste, the United States, the United Kingdom and Pakistan covering an acreage of approximately 22,000 square kilometers; and (iii) the total relinquishment of leases in Brazil and Mali for a total acreage of approximately 22,000 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, 2012. A gross acreage is one in which Eni owns a working interest.

	December 31, 2011	December 31, 2012						
	Total net acreage (a)	Number of interests	Gross developed (b) acreage (a)	Gross undeveloped acreage (a)	Total gross acreage (a)	Net developed (b) acreage (a)	Net undeveloped acreage (a)	Total net acreage (a)
EUROPE	**26,023**	**288**	**17,191**	**27,199**	**44,390**	**11,150**	**16,273**	**27,423**
Italy	**16,872**	**151**	**10,847**	**11,438**	**22,285**	**9,011**	**8,545**	**17,556**
Rest of Europe	**9,151**	**137**	**6,344**	**15,761**	**22,105**	**2,139**	**7,728**	**9,867**
Croatia	987	2	1,975		1,975	987		987
Norway	2,335	52	2,264	6,226	8,490	346	2,330	2,676
Poland	1,968	3		1,968	1,968		1,968	1,968
United Kingdom	1,014	65	2,055	647	2,702	776	138	914
Ukraine	45	12	50	3,840	3,890	30	1,911	1,941
Other Countries	2,802	3		3,080	3,080		1,381	1,381
AFRICA	**137,220**	**287**	**64,075**	**192,079**	**256,154**	**19,891**	**122,905**	**142,796**
North Africa	**30,532**	**119**	**31,988**	**17,691**	**49,679**	**14,066**	**7,324**	**21,390**
Algeria	9,065	41	2,640	1,158	3,798	1,071	161	1,232
Egypt	5,898	57	4,937	7,845	12,782	1,771	2,819	4,590
Libya	13,295	10	17,947	8,688	26,635	8,950	4,344	13,294
Tunisia	2,274	11	6,464		6,464	2,274		2,274
Sub-Saharan Africa	**106,688**	**168**	**32,087**	**174,388**	**206,475**	**5,825**	**115,581**	**121,406**
Angola	6,218	78	4,804	20,037	24,841	636	5,443	6,079
Congo	5,020	26	1,835	7,681	9,516	1,027	4,008	5,035
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		5,144	5,144		1,885	1,885
Kenya		3		35,724	35,724		35,724	35,724
Liberia		3		8,145	8,145		2,036	2,036
Mozambique	9,502	1		12,956	12,956		9,069	9,069
Nigeria	8,491	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	61,502	5		59,578	59,578		39,862	39,862
ASIA	**55,284**	**73**	**17,126**	**101,554**	**118,680**	**5,778**	**52,264**	**58,042**
Kazakhstan	**880**	**6**	**324**	**4,609**	**4,933**	**95**	**774**	**869**
Rest of Asia	**54,404**	**67**	**16,802**	**96,945**	**113,747**	**5,683**	**51,490**	**57,173**
China	5,365	11	200	10,456	10,656	39	10,456	10,495
India	9,206	11	206	16,546	16,752	109	6,099	6,208

Indonesia	17,719	13	1,735	28,490	30,225	656	19,078	19,734
Iran	820	4	1,456		1,456	820		820
Iraq	352	1	1,074		1,074	352		352
Pakistan	9,289	19	8,430	20,210	28,640	2,478	8,055	10,533
Russia	1,469	4	3,501	1,495	4,996	1,029	440	1,469
Timor Leste	6,740	2		5,148	5,148		4,118	4,118
Turkmenistan	200	1	200		200	200		200
Other Countries	3,244	1		14,600	14,600		3,244	3,244
AMERICAS	**10,209**	**409**	**4,571**	**14,180**	**18,751**	**3,074**	**6,001**	**9,075**
Brazil	795							
Ecuador	1,985	1	1,985		1,985	1,985		1,985
Trinidad & Tobago	66	1	382		382	66		66
United States	5,123	393	1,826	6,206	8,032	925	3,707	4,632
Venezuela	914	6	378	2,427	2,805	98	968	1,066
Other Countries	1,326	8		5,547	5,547		1,326	1,326
AUSTRALIA AND OCEANIA	**25,685**	**15**	**1,980**	**23,102**	**25,082**	**1,046**	**12,788**	**13,834**
Australia	25,647	14	1,980	22,338	24,318	1,046	12,750	13,796
Other Countries	38	1		764	764		38	38
Total	**254,421**	**1,072**	**104,943**	**358,114**	**463,057**	**40,939**	**210,231**	**251,170**

(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.

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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, 2012. 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 8,512 (3,213.1 of which represent Eni s share).

Productive oil and gas wells at Dec. 31, 2012 [(a)]

	Oil wells		Natural gas wells	
(units)	**Gross**	**Net**	**Gross**	**Net**
Italy	242.0	196.1	621.0	536.6
Rest of Europe	460.0	69.7	180.0	89.2
North Africa	1,447.0	702.3	154.0	59.2
Sub-Saharan Africa	2,858.0	542.2	383.0	27.6
Kazakhstan	102.0	29.1		
Rest of Asia	642.0	404.1	889.0	336.6
Americas	169.0	90.5	344.0	122.8
Australia and Oceania	7.0	3.8	14.0	3.3
Total including equity-accounted entities	**5,927.0**	**2,037.8**	**2,585.0**	**1,175.3**

(a) Multiple completion wells included above: approximately 2,203 (747.7 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 2012, Eni s oil and gas production amounted to 184 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 (54 operated onshore and 61 operated offshore).

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The Adriatic and Ionian Sea represents Eni s main production area for gas, accounting for 50% of Eni s domestic production in 2012. 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 26 production wells representing 30% of Eni s production in Italy and is treated by the Viggiano oil center. Oil produced is carried to Eni s refinery in Taranto via a 136-kilometer long pipeline. Gas produced is delivered to the national grid system.

Other main fields are Gela, Ragusa, Tresauro, Giaurone, Fiumetto and Prezioso in Sicily, which in 2012 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. The construction of a new gas treatment unit started at the end of 2012, targeting a production capacity of 104 kBBL/d.

Other development activities concerned: (i) production optimization at the Antonella, Barbara, Basil, Brenda, Gela, Naomi & Pandora and Porto Corsini fields; (ii) upgrading of compression and hydrocarbon treatment facilities at the production platform of the Barbara field; and (iii) linkage to the existing production facilities of the Colle Sciarra well (Eni s interest 50%).

In the medium-term, management expects a stable production plateau 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 UK. In 2012, the Rest of Europe accounted for 11% of Eni s total worldwide production of oil and natural gas.

Croatia. Eni has been present in Croatia since 1996. In 2012, Eni s production of natural gas averaged 23 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 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 as operator 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 123 kBOE/d in 2012.

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 2012 accounted for 78% of Eni s production in Norway.

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 2012 produced approximately 27 kBOE/d net to Eni and accounted for 22% 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 infilling wells, the development of the South Area extension, upgrading of existing facilities and optimization of water injection.

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 in 2014 with the production plateau of 100 kBBL/d.

In April 2012, Eni signed with Solveig Gas Norway AS an agreement for the sale of its 1.43% interest in the Gassled JV, a network of gas pipelines and terminals for natural gas transportation. The sale was closed at the end of 2012 with a consideration amount of approximately euro 130 million.

Eni was awarded four exploration licenses: (i) the PL091D license (Eni s interest 7.9%) in the Norwegian Sea; and (ii) PL697 (Eni operator with a 65% interest), the PL657 (Eni operator with an 80% interest) and the PL696 license (Eni s interest 30%) in the Barents Sea.

Exploration activities yielded positive results in the: (i) PL532 license (Eni s interest 30%) with the appraisal campaign for the assessment of mineral potential of the oil and gas Skrugard discovery and the new Havis oil and gas discovery. Both fields are planned to be put in production by means of a fast-track synergic development; and (ii) PL 533 license (Eni s interest 40%) with the gas and condensate Salina discovery.

Ukraine. In June 2012, Eni signed a Share Purchase Agreement with Ukrainian state-owned National Joint Stock Co, Nak Nadra Ukrayny, and Cadogan Petroleum Plc to acquire a 50.01% interest and operatorship of the Ukrainian company Westgasinvest Llc which currently holds subsoil rights to nine unconventional (shale) gas license areas in the Lviv Basin of Ukraine. These licenses cover approximately 3,800 square kilometers of acreage.

United Kingdom. Eni has been present in the UK since 1964. Eni s activities are carried out in the British section of the North Sea and the Irish Sea. In 2012, Eni s net production of oil and gas averaged 44 kBOE/d.

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

Eni holds interests in 13 production areas; in 1 of these, the Hewett Area, Eni is operator with an 89% interest. The other main fields are Elgin/Franklin (Eni s interest 21.87%), West Franklin (Eni s interest 21.87%), Liverpool Bay (Eni s interest 53.9%), J Block Area (Eni s interest 33%), Flotta Catchment Area (Eni s interest 20%) and MacCulloch (Eni s interest 40%), which in 2012 accounted for 91% of Eni s production in the UK.

In 2012, Eni signed an agreement for the divestment of the following development/production assets: Mariner (Eni s interest 20%), Andrew (Eni s interest 16.21%), Kinnoul (Eni s interest 16.67%), Flotta Catchment Area (Eni s interest 20%) and a few minor ones. At the end of the year the sale of Mariner was completed. The completion date for the other assets is expected in 2013.

Main development activities in 2012 were: (i) the construction of production and treatment facilities for the gas and liquids Jasmine field (Eni s interest 33%). Start-up is expected in 2013; and (ii) the construction of production platforms and linkage to nearby treatment facilities for the West Franklin field (Eni s interest 21.9%).

During 2012, a gas leak occurred on a well at the Elgin/Franklin field. Production for the field operated by an international oil company was stopped at the end of March.

Production resumed during the first quarter of 2013. The impact on 2012 production was estimated at approximately 7 mmBBL.

North Africa

Eni s operations in North Africa are conducted in Algeria, Egypt, Libya and Tunisia. In 2012, 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 2012, Eni s oil and gas production averaged 71 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) Block 212 (Eni s interest 22.38%) with discoveries already made; and (vi) Blocks 208 (Eni s interest 12.25%, non operated) and 405b (Eni s interest 75%) with ongoing development activities.

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 21% of Eni s production in Algeria in 2012. Zero gas flaring, in compliance with applicable country law, had been achieved in 2012.

Production in Blocks 401a/402a comes mainly from the ROD/SFNE and satellite fields and accounted for approximately 24% of Eni s production in Algeria in 2012.

The main fields in Block 403 are BRN, BRW and BRSW which accounted for approximately 18% of Eni s production in Algeria in 2012.

The main fields in Block 404 are HBN and HBNS and satellites which accounted for approximately 37% of Eni s production in Algeria in 2012.
In 2013, production started at the MLE field part of the MLE-CAFC integrated project in Block 405b (Eni s interest 75%). A natural gas treatment plant started operations with a gross production and export capacity of approximately 320 mmCF/d of gas, 15 kBBL/d of oil and condensates and 12 kBBL/d of GPL. Four export pipelines link it to the national grid system. Development activities progressed at the CAFC oil project. The project includes the construction of an oil treatment plant and synergies with the MLE production facilities. Production start-up is expected in 2015.

The MLE-CAFC integrated project targets a production plateau of approximately 33 kBOE/d net to Eni by 2016.

Block 208 is located South of Bir Rebaa where the El Merk project is progressing. The development program provides for the construction of a gas treatment plant for the liquid extraction with a gross capacity of approximately 600 mmCF/d, two oil trains with a gross capacity of 65 kBBL/d each and three export pipelines targeting a production plateau at approximately 18 kBBL/d net to Eni in 2015. Start-up is expected in 2013.

Egypt. Eni has been present in Egypt since 1954. In 2012, Eni s share of production in this Country amounted to 223 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 Melehia (Eni s interest 56%) 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 2012, 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.

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In 2012, Eni started-up the gas offshore Seth field located in the Ras el Barr concession (Eni s interest 50%). Production is processed at the El Gamil onshore plant. Production plateau is expected at approximately 170 mmCF/d (approximately 11 kBOE/d net to Eni).

Other activities for the year concerned the upgrading of the El Gamil and Abu Madi plants by adding new compression capacity to support production.

Through its affiliate Unión Fenosa Gas, Eni has an indirect interest in the Damietta natural gas liquefaction plant with a producing capacity of 5.1 mmtonnes/y of LNG corresponding to approximately 268 BCF/y of feed gas. Eni, together with other international oil company, have entered into an agreement to supply 310 mmCF/d for 17-year period. Natural gas supplies derived from the Taurt and Denise fields with 17 kBOE/d net to Eni of feed gas.

Exploration activities yielded positive results in the: (i) Belayim concession with the BLNE-2 and BMSW-1 oil discoveries that were linked to the existing facilities; (ii) Nile Delta offshore with the gas discoveries of Ha py-12, Taurt North-1, Seth South-1, Plio-1C and Nile Delta onshore with the El Qara N-2 gas discovery;
(iii) Meleiha development lease with the Rosa North-1X, Emry Deep 1X and 4X oil discoveries. The Emry Deep field started-up with approximately 18 kBBL/d (approximately 6 kBBL/d net to Eni); and
(iv) West Razzak development lease with the Aghar NN-1X oil discovery.

Libya. Eni started operations in Libya in 1959. In 2012, Eni s oil and gas production averaged 252 kBOE/d.

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 contract Areas A, B and D.

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

In the Offshore Area D, Eni was the first IOC to restart exploration activity after revolution, with the acquisition of about 2,600 square kilometers of 3D seismic survey from February to April 2012.

The onshore exploration activity was resumed in December 2012 by drilling the A1-108/4 exploration well that will reach a total depth of approximately 4,420 meters. This is the first well of an onshore exploration campaign that will continue in 2013 marking a relevant step in the full recovery of Eni s upstream activity in Libya.

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Management plans to complete the recovery of the full production plateau at its Libyan assets in the short term and then to assess possible options to upgrade certain projects.

Tunisia. Eni has been present in Tunisia since 1961. In 2012, Eni s production amounted to 15 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), MLD (Eni s interest 50%) and El Borma (Eni s interest 50%) onshore blocks.

Production optimization was carried out at the Baraka, Oued Zar, MLD and Adam fields.

Sub-Saharan Africa

Eni s operations in Sub-Saharan Africa are conducted mainly in Angola, Congo and Nigeria. In 2012, Sub-Saharan Africa accounted for 20% of Eni s total worldwide production of oil and natural gas.

Angola. Eni has been present in Angola since 1980. In 2012, 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%) in the North of the Angolan coast; (ii) Development Areas in the former Block 3 (Eni s interest ranging from 12% to 15%) in the offshore of the Congo Basin; (iii) Development Areas in the former Block 14 (Eni s interest 20%) in the deep offshore west of Block 0; and (iv) Development Areas in the former Block 15 (Eni s interest 20%) in the deep offshore of the Congo Basin.

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 35% 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%).

In the exploration and development phase, Eni operates Block 15/06 (Eni s interest 35%), where development is ongoing at the West Hub project. Project start-up is expected by mid 2014 with production peaking at 84 kBBL/d (25 kBBL/d net to Eni) in 2016.

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

Production started at the satellites Kizomba Phase 1 project in the Development Areas of former Block 15 with peak production at 72 kBBL/d (12 kBBL/d net to

Eni) expected in 2013.

In 2012, three development projects have been sanctioned: (i) the second phase of Kizomba satellites. The project includes the linkage of three additional discoveries to the existing FPSO. Start-up is expected in 2015; (ii) the Mafumeira field in Area A of Block 0. Development activities are in progress and start-up is expected in 2015; and (iii) the Lianzi discovery.

As part of the activities designed to reduce gas flaring in Block 0, activity progressed at the Nemba field in Area B, with completion expected in 2014. Once completed flared gas is expected to decrease by approximately 85% from current level. Other ongoing projects include the installation of a second compression unit at the Nemba platform.

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. The project has been sanctioned by the relevant Angolan Authorities. It envisages the development of 10,594 BCF of gas in 30 years. Exports start-up is expected in 2013. In the year a new agreement has been reached by the partners and local authorities for the sale of LNG on Asian and European markets.

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: (i) Block 15/06 with the oil Vandumbu 1 discovery, first commitment well of the second exploration period; and (ii) Block 2 with the Etele Tampa 7 well containing gas and condensates.

In the medium term, management expects to increase Eni s production to approximately 160 kBBL/d reflecting additions from ongoing development projects.

Congo. Eni has been present in Congo since 1968. In 2012, production averaged 98 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 65%), Kitina (Eni s interest 35.75%), 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.

In the exploration phase, Eni also holds interests in the Mer Très Profonde Sud deep offshore block (Eni s interest 30%), the Noumbi onshore permit (Eni s interest 37%) and the Marine XII offshore permit (Eni operator with a 65% interest).

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 within the activities aimed at zero gas flaring by 2013. Gas is sold under long-term contracts to power plants in the area including the CEC Centrale Electrique du Congo (Eni s interest 20%) a 300 MW generation capacity. These facilities will also receive in the future gas from the offshore discoveries of the Marine XII permit. In 2012, M Boundi contractual supplies were approximately 106 mmCF/d (approximately 17 kBOE/d net to Eni).

In 2012, the development project for the gas and condensates Litchendjili field in Block Marine XII has been sanctioned. The project provides for the installation of a production platform, the construction of transport facilities and of an onshore treatment plant. Production will also feed the CEC power station.

Other activities in the area concerned the optimization of producing fields of Foukanda and Mwafi by means of Eni s enhanced recovery technology.

Exploration activities yielded positive results in offshore Block Marine XII with the Nene Marine 1 gas discovery.

In the medium term, management expects to increase Eni s production in Congo due to the integration and development of recently acquired assets as well as projects underway, targeting a level in excess of 120 kBOE/d by 2016.

Democratic Republic of Congo. Eni has been present in the Democratic Republic of Congo since 2010 where it retains a 55% interest and operatorship in Ndunda Block. At present no relevant activities are conducted in this Country.

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 in the Offshore Cape Three Points license with the: (i) Sankofa East-1X well, the first commercial oil discovery in the area that flowed at approximately 5 kBBL/d of high quality oil in test production; and (ii) the Sankofa East-2A appraisal well that confirmed the high mineral potential of the western area. Studies for a fast track commercial development are underway.

In July 2012, Eni and its partners in the OCPT license, signed a Memorandum of Understanding with the Ministry of Energy of Ghana for the development and marketing of discovered gas resources.

Kenya. In July 2012, Eni was awarded three product sharing contracts by the Government of Kenya. The contracts relate to the L-21, L-23 and L-24 exploration blocks which are located in the deep and ultra-deep waters of the Lamu Basin covering an area of approximately 36,000 square kilometers.

Liberia. In August 2012, Eni acquired a 25% interest in three blocks offshore Liberia covering an area of 8,145 square kilometers at a maximum water depth of 3,000 meters. The joint venture is operated by another international oil company. This operation marks Eni s entry into Liberia.

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 years duration is awarded in respect of any approved Development and Production Area.

In 2011, Eni made the important Mamba gas discovery.

On March 13, 2013, Eni signed an agreement with CNPC/Petrochina to sell 28.57% of the share capital of the subsidiary Eni East Africa SpA, which currently owns 70% interest in Area 4 for an agreed price equal to $4,210 million. The deal is subject to approval by relevant authorities. Once finalized, CNPC indirectly acquires, through its 28.57% equity investment in Eni East Africa, a 20% interest in Area 4, while Eni will retain the 50% interest through the remaining controlling stake in Eni East Africa.

In 2012, exploration and appraisal campaigns achieved new exploration successes in Area 4 with the Mamba South 2, Mamba North 1, Mamba North East 1 and 2 as well as Coral 1 and 2 gas discoveries. The latest Mamba North East and Coral discoveries are particularly significant since they confirm a new exploration play in Area 4, which is independent from Mamba s new discovery structure. Management believes that this exploration area contains a large amount of gas resources. The final investment decision is expected in 2014.

In early 2013, a new exploration success was achieved with the delineation of the Coral 3 gas well that is estimated to improve the mineral potential of the area operated by Eni. The wells, drilled at the Coral prospect, showed excellent results during the production test.

Eni plans to drill a further delineation well, Mamba South 3 before moving back to exploration drilling in the Southern sector of Area 4.

In December 2012, Eni signed an agreement with Anadarko Petroleum Corp establishing basic principles for the coordinated development of common offshore activities in Area 4, operated by Eni and Area 1, operated by Anadarko. Furthermore, the two companies plan to jointly design and construct onshore LNG liquefaction facilities in Northern

Mozambique.

Nigeria. Eni has been present in Nigeria since 1962. In 2012, Eni s oil and gas production averaged 149 kBOE/d located mainly onshore and offshore the Niger Delta.

In 2012, Eni completed the divestment of a 5% stake in Blocks OMLs 30, 34 and 40.

In the development/production phase Eni operates onshore Oil Mining Leases (OML) 60, 61, 62 and 63 (Eni s interest 20%) and offshore OPL 245 (Eni s interest 50%), OML 125 (Eni s interest 85%), 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 25 onshore blocks and a 12.86% interest in 5 conventional offshore blocks.

In the exploration phase Eni operates offshore Oil Prospecting Leases (OPL) 244 (Eni s interest 60%), OML 134 (Eni s interest 85%) and 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.

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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 the state-owned company.

Starting from March 21, 2013, the oil production of the onshore Swamp area mainly in the Bayelsa State in Nigeria has been temporarily shut down due to the increasing bunkering and sabotage acts on the oil trunk lines. Currently, the area produces from 9 fields through 4 flow stations (Ogbainbiri, Tebidaba, Clough Creek, Obama). A detailed survey of the lines affected by the bunkering is in progress in order to identify and repair the damages suffered.

In service contract OML 119, Phase 2A achieved production start-up and is expected to peak at 15 kBBL/d.

In Blocks OMLs 60, 61, 62 and 63, activities progressed to support gas production to feed the Bonny liquefaction plant. Development activities concerned the Tuomo gas field aimed at supplying 170 mmCF/d net to Eni of feed gas to the sixth train for 20 years. The flowstation at Ogbainbiri is nearing completion. This facility will ensure approximately 310 mmCF/d of feed gas to the fourth and the fifth trains. Flaring down program continued with the upgrading of the flowstation at the Idu field with a decline in flared gas of 45 mmCF/d NAOC JV share.

In Block OML 28 (Eni s interest 5%) the integrated oil and natural gas project in the Gbaran-Ubie area is underway. The development plan provides for the construction of a Central Processing Facility (CPF) with treatment capacity of approximately 1 BCF/d of gas and 120 kBBL/d of liquids in order to feed gas the Bonny liquefaction plant.

Activities progressed at the Abo Phase 3 project in Block OML 125. Start-up is expected in 2013.

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-kilometer west of Bonny. This plant is expected to start operating in 2017 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.

Exploration activities yielded positive results in: (i) Block OPL 282 with the Tinpa 1 well containing oil; and (ii) Block OPL 2009 with the Afiando 1 and 2 oil wells.

In the medium term, management expects to increase Eni s production in Nigeria to approximately 190 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 2012, 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 (NCSPSA). 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. Development activities are ongoing at the Kashagan field, targeting the production start-up by mid-2013. 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, and the international oil companies Total, Shell and ExxonMobil, each with a participating interest currently of 16.81%, ConocoPhillips with 8.40%, 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).

In 2012, the Experimental Program progressed at the last phase of mechanical completion while commissioning and pre-start up activities achieved an advanced stage. Production plants are planned to be handed over to the production organization and tested. Start-up and commercial production is expected by the end of the first half of 2013, as agreed with the Republic of Kazakhstan.

The Phase 1 (Experimental Program) is targeting an initial production capacity of 150 kBBL/d; by 2014 a second treatment train and compression facilities for gas reinjection 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 and sanction is expected in 2013 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, 2012, Eni s proved reserves booked at the Kashagan field amounted to 568 mmBOE, recording an increase compared to 2012 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, 2010, Eni s proved reserves booked for the Kashagan field amounted to 569 mmBOE, recording a decrease of 19 mmBOE with respect 2009 mainly due to price effect.

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.

As of December 31, 2011, the aggregate costs incurred by Eni for the Kashagan project capitalized in the Consolidated Financial Statements amounted to $6.7 billion (euro 5.2 billion at the EUR/USD exchange rate of December 31, 2011). This capitalized amount included: (i) $5.1 billion relating to expenditure incurred by Eni for the development of the oil field; and (ii) $1.6 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 (FPSA) 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. The contracting companies transferred 10% of their rights and interest in the project to Kazakhstan s KazMunaiGas for $1 billion net cash consideration ($325 million being

Eni s share). From the effective date of June 28, 2012, Eni s interest in the Karachaganak project has been reduced to 29.25% from the 32.5% previously held. The agreement also includes the allocation of an additional 2 mmtonnes/y capacity in the Caspian Pipeline.

In 2012, production of the Karachaganak field averaged 239 kBBL/d of liquids (61 net to Eni) and 788 mmCF/d of natural gas (202 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 (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.

Phase 3 of the Karachaganak project is currently under study. The project is aimed at further developing gas and condensates reserves by means of the installation, in stages, of gas treatment plants and re-injection facilities to increase gas sales and liquids production. The development plan is currently in the phase of technical and marketing definition to be presented to the relevant Authorities.

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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.

As of December 31, 2010, Eni s proved reserves booked for the Karachaganak field amounted to 557 mmBOE, recording a decrease of 76 mmBOE with respect to 2009 due to price effect and production of the year.

Rest of Asia

In 2012, Eni s operations in the rest of Asia accounted for 8% of its total worldwide production of oil and natural gas.

China. Eni has been present in China since 1984 and its activities are located in the South China Sea. In 2012, Eni s production amounted to 9 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 the Rongchang Block with shale gas resources, over an area of approximately 2,000 square kilometers, located in the Sichuan Basin, in China.

Hydrocarbons are 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 is delivered through a sealine to the Zhuhai Terminal and sold to the Chinese National Co CNOOC. Oil is mainly produced from HZ25-4 field (Eni s interest 49%). Activity is operated by the CACT-Operating Group (Eni s interest 16.33%).

In April 2012, Eni and CNOOC signed a Production Sharing Contract for the exploration of offshore Block 30/27, located in the South China Sea. The exploration commitment provides for the acquisition of a 3D seismic survey and the drilling of one well to be performed during the first exploration period. Eni will be the Operator of the project, with a 100% interest. In the case of a discovery, CNOOC has a back-in right up to 51%.

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 2012, Eni s production amounted to 2 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 2012, Eni s production mainly composed of gas, amounted to 14 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.

In May 2012, Eni was awarded the East Sepinggan Block (Eni s interest 100%), located offshore in Kutei Basin supported by the nearby Bontang LNG processing facility. The commitment activity foresees performing of geological and geophysical studies, acquisition of seismic data and the drilling of one well over the next three years.

The development plan of the operated Jangkrik (Eni s interest 55%) and Jau (Eni s interest 85%) offshore fields progressed. 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 2016 with a production peak of 80 kBOE/d (41 kBOE/d net to Eni). The Jau project provides for the drilling of production wells and the linkage to onshore plants via pipeline.

Appraisal activities related to a coal bed methane project progressed at the Sanga Sanga PSC (Eni s interest 37.8%). Predevelopment activities are underway leveraging on the synergy opportunities provided by the existing production and treatment facilities also including the Bontang LNG plant.

Development activities are underway at the Indonesia Deepwater Development project (Eni s interest 20%), located in East Kalimantan, to ensure gas supplies to the Bontang plant. The project initially provides for the linkage of the Bangka field to existing facilities, then for the integrated development of four fields through a first Hub serving Gendalo, Gandang, Maha and a second Hub for Gehem.

Iran. Eni has been operating in Iran for several years under four Service Contracts (South Pars, Darquain, Dorood and Balal, the 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 the above mentioned projects have been completed or substantially completed; the last one, the Darquain project, is being handed over to NIOC. Operatorship has already been transferred to a NIOC affiliate. When the final hand over of operations will be completed, Eni s involvement will essentially consist of being reimbursed for its past investments. In 2012, Eni s contractual reimbursement were equivalent to a production of 3 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 consideration 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 32.8% interests in Zubair oil field.

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

In 2012, production of the Zubair field averaged 262 kBBL/d (18 kBBL/d net to Eni).

Development activities progressed at the Zubair oil field. The contracts have been awarded for the first expansion of the actual production capacity to double the current production level in 2014.

Pakistan. Eni has been present in Pakistan since 2000. In 2012, Eni s production mainly composed of gas amounted to 55 kBOE/d.

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

Eni s main permits in the Country are Bhit (Eni operator with a 40% interest), Sawan (Eni s interest 23.68%) and Zamzama (Eni s interest 17.75%), which in 2012 accounted for 76% of Eni s production in Pakistan.

In December 2012, Eni signed an agreement with the Pakistani Authorities and the state oil and gas company OGDCL for the acquisition of a 25% stake and the operatorship of exploration license Indus Block G, located in ultra deep water offshore of the Indus Basin over an area of approximately 7,500 square kilometers.

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Exploration activity yielded positive results with a relevant gas discovery in the onshore concession Badhra Area B. A further outline of the discovery will require additional wells.

In 2012, the Badhra B North-1 well has been linked to the Bhit plant and started-up in October 2012, flowing at approximately 14 mmCF/d of gas net to Eni.

Russia. Eni has been present in Russia since 2007 following the acquisition of Lot 2 in the liquidation procedure of bankrupt Russian company Yukos. Eni acquired a 29.4% interest in the joint venture Severenergia which currently owns important amounts of proved undeveloped gas reserves in the Yamal Peninsula in Siberia.

In 2012, Eni s production mainly composed of gas amounted to 11 kBOE/d. Following start-up of the first and the second train of the Samburgskoye field, a production level is expected at 95 kBOE/d (28 kBOE/d net to Eni). Development activities progressed with completion expected in 2015 and production peak of 146 kBOE/d (43 kBOE/d net to Eni) in 2016. The gas production is sold to Gazprom under an agreement signed in September 2011 while the condensate production is sold to Novatek under the relevant agreement signed in 2012. Eni retains the right to lift its share of natural gas and sell it to any third parties in the domestic market.

Planned activities progressed at the sanctioned Urengoiskoye field (Eni s interest 29.4%). Start-up is expected in 2014.

In April 2012, Eni and Rosneft signed an agreement related to a strategic cooperation whereby the two companies will set up joint ventures (Eni 33.33%) for the exploration and development of the Fedynsky and Tsentralno-Barentsevsky licenses, located offshore Russia in the Barents Sea, and Zapadno-Cernomorsky, located offshore Russia in the Black Sea. Finalization is expected in 2013.

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 2012, Eni s production averaged 10 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 oil field. 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. In June and July 2012, Eni acquired the operatorship (50% interest) of three exploration blocks located offshore Vietnam, in the Song Hong and Phu Khanh basins. The three blocks cover approximately 21,000 square kilometers of acreage. These basins are estimated to contain 10% of Vietnam s hydrocarbon resources, mainly gas. The

Company plans to make significant investment to explore for hydrocarbons in the acquired acreage by drilling four wells.

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.

Americas

In 2012, Eni s operations in the Americas accounted for 8% 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 2012, Eni s production averaged 25 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.

Trinidad and Tobago. Eni has been present in Trinidad and Tobago since 1970. In 2012, 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, Poinsettia, 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 cost and sold under long-term contracts. LNG production is manly 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 and more recently onshore and offshore in Alaska.

In 2012, Eni s oil and gas production mainly derived from the Gulf of Mexico with an average of 86 kBOE/d.

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

Eni holds interests in 281 exploration and production blocks in the Gulf of Mexico of which 172 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 Thunderhawk (Eni s interest 25%) fields.

Development activities mainly concerned: (i) drilling activities at the Allegheny, Appaloosa and Devils Towers operated fields; (ii) production optimization of the Front Runner (Eni s interest 37.5%), Europa, Popeye (Eni s interest 50%) and Thunderhawk fields; and (iii) the start-up of drilling programs at the Hadrian South (Eni s interest 30%) and St. Malo (Eni s interest 1.25%) fields.

Exploration outlining activity of the Heidelberg oil discovery (Eni s interest 12.5%) in the Gulf of Mexico yielded positive results. Studies are underway for a fast track development.

In order to achieve the highest security standards of operations, Eni entered the HWGC 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".

Development activity progressed at the Alliance area (Eni s interest 27.5%), in the Fort Worth Basin in Texas. This area, including gas shale reserves, was acquired following a strategic partnership between Eni and Quicksilver. In particular, 12 new wells entered in production and contributed to a total production of approximately 10 kBOE/d net to Eni in the year.

In March 2013, Eni was awarded five offshore blocks located in Mississippi Canyon and Desoto Canyon, in the Gulf of Mexico.

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Eni holds interests in 111 exploration and development blocks in Alaska, with interests ranging from 10 to 100% and for 54 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 9 kBBL/d net to Eni in 2012.

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

Venezuela. Eni has been present in Venezuela since 1998. In 2012, Eni s production averaged 9 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 oil fields 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 started-up at the giant Junin 5 field (Eni s interest 40%) with 35 BBBL of certified heavy oil in place, located in the Orinoco oil belt. Early production of the first phase is expected at plateau of 75 kBBL/d in 2015, targeting a long-term production plateau of 240 kBBL/d to be reached by 2018. The project provides also for the construction of a refinery with a capacity of approximately 350 kBBL/d. The drilling activity started during the year. 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. Eni signed a loan agreement in the fourth quarter 2012.

Venezuelan relevant Authority sanctioned the development plan of the Perla gas discovery, located in the Cardón IV Block (Eni s interest 50%), in the Gulf of Venezuela. PDVSA exercised its 35% back-in right in 2012 and the completion of the stake transfer is expected in 2013. Eni retains a 32.5% joint controlled interest in the company.

The early production phase includes the utilization of the already successfully drilled discovery/appraisal wells and the installation of production platforms linked by pipelines to the onshore treatment plant. Target production of approximately 300 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. In 2012, the FIDs of the further phases were sanctioned.

Activity progressed at the Corocoro producing field (Eni s interest 26%), in the Gulfo de Paria. In 2012, the start-up of the Central Production Facility (CPF) allowed to achieve a production peak of approximately 42 kBBL/d (approximately 11 kBBL/d net to Eni).

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, the latter coinciding with the Corocoro oil field area.

Australia and Oceania

Eni s operations in Australia and Oceania area are conducted mainly in Australia. In 2012, 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 2012, Eni s production of oil and natural gas averaged 36 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 9 exploration licenses.

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 2012 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 2012 amounted to approximately $22 million. In addition, in connection with its remaining Iranian operations, in 2012 Eni paid approximately $6 million for social security, withholding tax, corporate tax and rental tax.

In 2012, Eni s production in Iran averaged 3 kBOE/d, representing less than 1% of the Eni s total production for the year. We booked revenues of $128 million in 2012 in connection with our share of equity production and we reported a net loss of $69 million at our Iranian operations. As of the balance sheet date Eni had outstanding trade receivables amounting to euro 270 million towards Iranian oil national companies which were recorded in connection with revenues recognized in 2012 and in previous reporting periods. In 2012, we collected cash payments for a total of $107 million. Those revenues and trade receivables related to the recovery of the costs incurred by Eni in its

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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 $44 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. In addition, in 2012 we purchased 498 ktonnes of Iranian crude oil from NIOC and we paid NIOC $396 million in 2012, for those purchases. We believe that we made no profits on those purchases as our refining margins for the year 2012 were unprofitable on average. Those purchase transactions were entered into pursuant to a waiver granted by the U.S. Department of State as disclosed under Item 3 Risk factors Political considerations Risks associated with our presence in sanction targets . Also as a consequence of EU restrictive measures, in June 2012 Eni ceased to import Iranian crude oil with the exception of those volumes necessary to collect outstanding receivables towards Iranian counterparties, as allowed by the European Union sanctions regime.

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 2012, Eni s worldwide sales of natural gas amounted to 95.32 BCM, including 2.73 BCM of gas sales made directly by Eni s Exploration & Production segment. Sales in Italy amounted to 34.78 BCM, while sales in European markets were 51.02 BCM that included 2.73 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, regasification, storage and distribution of natural gas in Italy.

Marketing of natural gas

The outlook in the Europe on 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 2013 and beyond, particularly in the Italian market. A weaker-than-anticipated demand growth over the short term 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 off-take 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 outside 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 margins will weaken too, due to a number of negative catalysts including competitive pressure, an ongoing shift to index selling prices to hub benchmarks at large client segments, the current level of minimum take volumes at Italian operators which are well above market dimension, and finally the expected measures to be implemented by the Italian administration to cut the gas tariffs to residential customers. 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 2013 and recover the profitability in subsequent years leveraging contract renegotiations, an expected realignment of actual market imbalances and a gradual recovery in the spreads between the oil-linked cost of gas supplies and selling prices at spot markets.

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 allowing the counterparties to renegotiate the economic terms and other conditions periodically, in relation to ongoing changes in the gas scenario. Currently management is seeking to renegotiate about 80% of the Company s supplies in order to reduce the purchase costs by aligning them to the spot prices at continental hub and improve contractual flexibility targeting to mitigate the take-or-pay risk.

In a scenario of continuing weak demand and strong competition, management plans to retain the Company s market share in Italy and Europe by leveraging improved costs in procurement and logistics, and effective commercial actions.

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.

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".

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 2012, gas demand in Europe declined by 2% (down by 4% in Italy) 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; and
- EU policies intended to reduce 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 greenhouse gas (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%.

Management now expects EU demand to increase from around 478 BCM in 2012 to around 526 BCM by 2016, and to close to 552 BCM in 2020, corresponding to an average growth rate of approximately 1.8% along the period. Gas demand in Italy is expected to grow with an average rate of approximately 1.7% in the same period. The projected level of gas demand in 2016 is significantly below the level recorded in the pre-crisis years.

On the plus side, the 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 UK.

On the supply-side, gas availability remains 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 United States has reduced the Country s dependence on LNG imports due to commercial development of large non-conventional gas resources. As a result of those drivers, we expect that current market imbalances will continue over the next two to three years. Looking beyond, however, we expect the European market to rebalance due to a growing energy demand coming from the developing economies in China, India and other emerging countries in East Asia, Middle East and South America where, between now and 2015, we expect that consumption will increase significantly mainly driven by robust rates of economic development. This will help absorb part of worldwide LNG supplies which are currently being delivered to Europe. Additionally we expect that gas production in Europe will progressively decline due to mature field depletion. However there are also some risks in the demand scenario. In fact, management believes that it is possible that the U.S. Administration might speed up the process to monetize the Country s large reserve base of shale gas by giving permission to reconvert re-gasification plants into LNG export facilities. Furthermore, 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). Finally, it is difficult to estimate the long-term impact of the current European economic slowdown on gas demand, the effectiveness of EU Member States initiatives to achieve the committed targets in reducing energy intensity and the evolution of the role of renewables in the production of electricity.

Planned actions in marketing of natural gas

Over the 2013-2016 period, Eni s strategy will focus on certain distinct commercial objectives to recover profitability in a difficult market:

- to maintain its leadership in the Italian market mainly by strengthening the customer base in the valuable segments of retail consumers and small and medium businesses;
- to consolidate Eni s position in Europe in the business gas market, where the Company has a well balanced portfolio in terms of geographies, customer segments and contract duration;
- to focus on more profitable segments;
- to increase LNG sales in profitable markets outside Europe; and
- maximize sales volumes in order to mitigate the take-or-pay risk.

In particular management plans to regain market share in Italy and to expand sales in European target markets by leveraging first of all on the improved competitiveness of the Company s cost position reflecting the benefit of the renegotiation of its supply contracts, the quality of its offer, including risk management and transport and storage contracts, pricing formulas and commercial options that are designed to suit customers needs. In particular, in the retail segment in Italy Eni s campaign will focus on a combined commercial offer "luce, gas, carburanti" (electricity, gas and fuels) and the adoption of lean marketing procedures to facilitate customers tasks and optimization of commercial channels (such as agencies, remote selling, energy stores) with a strong focus on web channels.

In order to increase exposure to the retail segment, management plans to expand its customer base in Italy and outside Italy, by almost 3 million clients in the next four years to reach a total of 14 million customers by 2016, strengthening Eni s position in this segment in particular in Italy, through our distinctive offer "eni 3" (gas, electricity and fuels) and innovative sales channels. To retain more sophisticated customers in both the large and medium to small enterprises segment across Europe, the Company is ready to launch new innovative commercial offers based on multiple pricing options and volume flexibility.

Supply of natural gas

In 2012, Eni s consolidated subsidiaries supplied 86.74 BCM of natural gas, representing an increase of 3.36 BCM, or 4% from 2011.

Gas volumes supplied outside Italy (79.19 BCM from consolidated companies), imported in Italy or sold outside Italy, represented approximately 91% of total supplies, an increase of 3.03 BCM, or 4%, from 2011, mainly reflecting higher volumes purchased from Libya (up 4.23 BCM), almost tripled from 2011 when the GreenStream gas pipeline had been shutdown.

Increased volumes were purchased also from the Netherlands (up 0.95 BCM), and from Algeria (up 0.51 BCM). Declines were recorded in gas purchases from Russia (down 1.17 BCM) due to the recovery of Libyan supplies, the UK (down 0.37 BCM) and Norway (down 0.17 BCM). Supplies in Italy (7.55 BCM) increased slightly from 2011 also due to higher domestic production that offset the decline of mature fields. In 2012, main gas volumes from equity production derived from: (i) Italian gas fields (6.7 BCM); (ii) certain Eni fields located in the British and Norwegian sections of the North Sea (1.9 BCM); (iii) Libyan fields (1.8 BCM) increasing by almost 1.2 BCM due to the effect of force majeure registered in 2011; (iv) the United States (1.6 BCM); and (v) other European areas (Croatia with 0.2 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 18 BCM representing 18% 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	2010	2011	2012
		(BCM)	
Italy	**7.29**	**7.22**	**7.55**
Outside Italy	**75.20**	**76.16**	**79.19**
Russia	*14.29*	*21.00*	*19.83*
Algeria (including LNG)	*16.23*	*13.94*	*14.45*
Libya	*9.36*	*2.32*	*6.55*
the Netherlands	*10.16*	*11.02*	*11.97*
Norway	*11.48*	*12.30*	*12.13*
the United Kingdom	*4.14*	*3.57*	*3.20*
Hungary	*0.66*	*0.61*	*0.61*
Qatar (LNG)	*2.90*	*2.90*	*2.88*
Other supplies of natural gas	*4.42*	*6.16*	*5.43*
Other supplies of LNG	*1.56*	*2.34*	*2.14*
Total supplies of subsidiaries	**82.49**	**83.38**	**86.74**
Withdrawals from (input to) storage	(0.20)	1.79	(1.35)
Network losses, measurement differences and other changes	(0.11)	(0.21)	(0.28)
Volumes available for sale of Eni s subsidiaries	**82.18**	**84.96**	**85.11**
Volumes available for sale of Eni s affiliates	**9.23**	**8.94**	**7.48**
E&P volumes	**5.65**	**2.86**	**2.73**
Total volumes available for sale	**97.06**	**96.76**	**95.32**

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 16 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 off-takes 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. From the beginning of the downturn in the European gas market up to date, Eni has incurred the take-or-pay clause as the Company off-took lower volumes than its minimum take obligations accumulating deferred costs for an amount of euro 2.37 billion (net of limited 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 anticipated to remain stable in 2013 and to grow at a moderate pace in subsequent years, management intends to adopt adequate initiatives to mitigate the financial exposure 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 Italian gas intermediaries are obliged to fulfill. The initiatives to mitigate the take-or-pay risk include contract renegotiations which may temporarily reduce the annual minimum take, more flexible off-take conditions such as change in the delivery point or the possibility to replace supplies via pipeline with equivalent volumes of LNG. Based on the Company s selling programs and higher flexibility already achieved or to be achieved through the above mentioned renegotiations, management believes that it is likely that in the 2013-2016 period Eni will manage to fulfill its minimum take obligations associated with its supply contracts thus minimizing the risk on liquidity.

These projections could be subject to the risks of further contraction in demand or total addressable market. As to the deferred costs stated in the balance sheet, 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 off-taken in the long term in accordance to contractual term thus recovering the cash advances paid to suppliers.

This forecast is subject to the risk factors described in "Item 3 Risk factors" and in our outlook in "Item 5 Operating and financial review and prospects".

Sales of natural gas

In 2012, sales of natural gas were 95.32 BCM, down 1.44 BCM or 1.5% from 2011. Sales included Eni s own consumption, Eni s share of sales made by equity-accounted entities and E&P sales in Europe and in the Gulf of Mexico.

Despite a 4% decline in natural gas demand, sales volumes on the Italian market were substantially stable at 34.78 BCM (up 0.10 BCM, or 0.3% from 2011). Lower sales to the power generation segment (down 1.76 BCM), industrial customers (down 0.28 BCM) and wholesalers (down 0.51 BCM), due to the negative scenario and increasing competitive pressure, were offset by higher sales on the Italian exchange for gas and spot markets (up 2.28 BCM) and at a lower extent to the residential segment (up 0.22 BCM) reflecting efficient commercial initiatives.

Sales to shippers were down 0.51 BCM, or 15.7%, due to the release of certain supply contracts despite the recovery of Libyan supplies.

Sales on target markets in Europe of 48.29 BCM showed a slight decline from 2011 (down 2.9%). This decline was mainly due to a decline in sales in Benelux (down 3.53 BCM) and in the Iberian Peninsula (down 1.19 BCM) due to the exclusion of Galp sales after the loss of control offset only in part by increases recorded in France (up 1.35 BCM) also and Germany/Austria (up 1.31 BCM) due commercial initiatives.

Sales to markets outside Europe increased by 0.55 BCM due to higher LNG sales in the Far East, in particular in Japan.

E&P sales in Northern Europe and in the United States (2.73 BCM) declined by 0.13 BCM due to lower sales in the North Sea.

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

Natural gas sales by entities	**2010**	**2011**	**2012**
		(BCM)	
Total sales of subsidiaries	**82.00**	**84.37**	**84.67**
Italy (including own consumption)	*34.23*	*34.60*	*34.66*
Rest of Europe	*46.74*	*45.16*	*44.94*
Outside Europe	*1.03*	*4.61*	*5.07*

Total sales of Eni s affiliates (Eni s share)	**9.41**	**9.53**	**7.92**
Italy	*0.06*	*0.08*	*0.12*
Rest of Europe	*7.78*	*7.82*	*6.08*
Outside Europe	*1.57*	*1.63*	*1.72*
Total sales of G&P	**91.41**	**93.90**	**92.59**
E&P in Europe and in the Gulf of Mexico [(a)]	5.65	2.86	2.73
Worldwide gas sales	**97.06**	**96.76**	**95.32**

(a) E&P sales include volumes marketed by the Exploration & Production division in Europe (2.33, 2.29 and 2.06 BCM in 2010, 2011 and 2012, respectively) and in the Gulf of Mexico (3.32, 0.57 and 0.67 BCM in 2010, 2011 and 2012, respectively).

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Natural gas sales by market	**2010**	**2011**	**2012**
		(BCM)	
ITALY	**34.29**	**34.68**	**34.78**
Wholesalers	4.84	5.16	4.65
Gas release	0.68		
Italian gas exchange and spot markets	4.65	5.24	7.52
Industries	6.41	7.21	6.93
Medium-sized enterprises and services	1.09	0.88	0.81
Power generation	4.04	4.31	2.55
Residential	6.39	5.67	5.89
Own consumption	6.19	6.21	6.43
INTERNATIONAL SALES	**62.77**	**62.08**	**60.54**
Rest of Europe	**54.52**	**52.98**	**51.02**
Importers in Italy	8.44	3.24	2.73
European markets	46.08	49.74	48.29
Iberian Peninsula	*7.11*	*7.48*	*6.29*
Germany-Austria	*5.67*	*6.47*	*7.78*
Benelux	*15.64*	*13.84*	*10.31*
Hungary	*2.36*	*2.24*	*2.02*
UK-Northern Europe	*4.45*	*4.21*	*4.75*
Turkey	*3.95*	*6.86*	*7.22*
France	*6.09*	*7.01*	*8.36*
Other	*0.81*	*1.63*	*1.56*
Extra European markets	**2.60**	**6.24**	**6.79**
E&P in Europe and in the Gulf of Mexico	**5.65**	**2.86**	**2.73**
WORLDWIDE GAS SALES	**97.06**	**96.76**	**95.32**

European markets

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

Benelux. Eni s 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 2012, sales in Benelux were mainly directed to industrial companies, power generation and wholesalers and amounted to 10.31 BCM (13.84 BCM in 2011), down by 3.53 BCM, or 25.5%, due to rising competitive pressure, in particular in the wholesalers segment. In 2012, Eni launched its brand in the business and retail gas and power market in Belgium. The Eni brand substituted that of local operators acquired in the past few years with the aim of consolidating its leadership on 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 2012, sales in France amounted to 8.36 BCM (7.01 BCM in 2011), an increase of 1.35 BCM, or 19.3%, from a year ago. In 2012, Eni launched its brand in France, substituting 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 2012 approximately 4.40 BCM in Germany and 0.94 BCM in Austria through its associate GVS (GasVersorgung Süddeutschland GmbH - Eni 50%) which sold approximately 4.48 BCM in 2012 (2.24 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 2012, total sales in the Germany/Austria market amounted to 7.78 BCM, an increase of 1.31 BCM, or 20.2%, from a year ago.

Iberian Peninsula

Portugal. From the second half of 2012 due to the divestment of a stake in Galp and exit from the shareholders pact, Eni ceased reporting the share of gas volumes marketed by Galp in the Portuguese market due to the loss of significant influence on the investee.

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 2012, UFG gas sales in Europe amounted to 4.82 BCM (2.41 BCM Eni s share). UFG holds an 80% interest in the Damietta liquefaction plant, on the Egyptian coast (see below), and a 7.36%

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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 2012, Eni sales in Spain amounted to 5.24 BCM decreasing from a year ago. In 2012, total sales in the Iberian Peninsula amounted to 6.29 BCM, a decrease of 1.19 BCM, or 15.9%, from a year ago.

Turkey. Eni sells gas supplied from Russia and transported via the Blue Stream pipeline. In 2012, sales amounted to 7.22 BCM, an increase of 0.36 BCM, or 5.2% from a year ago.

UK-Northern Europe. Eni through its subsidiary ETS markets in the UK 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 2012, sales amounted to 4.75 BCM, an increase of 12.8% from a year ago.

The Deborah Gas Storage Project (DGSP) is a seasonal gas storage development planned for 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.

FEED activities, as well as site activities (i.e. onshore surveys) were carried out throughout 2010-2011. Concerning the permits and consents, an agreement to lease the offshore field has been reached with The Crown Estate and a Gas Storage License has been granted by DECC while the North Norfolk District Council (NNDC) has approved the Deborah Project planning application subject to conditions. Appraisal works on the Deborah reservoir were also progressed throughout 2010, including the drilling and completion of an appraisal well and the related tests. An approved equity sales process to dilute the Eni stake was conducted throughout 2011, as well as a market based long term capacity allocation process in 2010. Ongoing work with UK government ministries and regulatory agencies continued in 2011 and across 2012 in order to promote the continued role of natural gas within the UK energy mix and support the economic case for the DGSP. The aim being to secure a support mechanism guaranteeing reasonable revenues to underwrite the DGSP investment. At the end of 2012 the Department of Energy and Climate Change published its Gas Generation Strategy and received Ofgem s Security of Supply report. It has now launched its own deep analysis of the costs and benefits of an intervention to support Gas Storage investment aiming to deliver its recommendations in Spring 2013.

However, Government legislation is not expected to come into force until 2014, Eni therefore targets 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. Through its subsidiary Distrigas, 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.

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.

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USA

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 the third quarter of 2009. In consideration of a changed demand outlook, on March 1, 2010, Eni renegotiated certain terms of the contract with the U.S. company Cameron LNG, relating to the farming out of a share of re-gasification capacity resulting in an entitlement to Eni of a daily send-out of 572,000 mmbtu (approximately 5.7 BCM/y). Considering current oversupply conditions in the U.S. gas market, the Brass project (West Africa) for developing gas reserves to fuel the Cameron plant has been rescheduled with start-up in 2017.

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	**2010**	**2011**	**2012**
		(BCM)	
G&P sales	**11.2**	**11.8**	**10.5**
Italy	0.2		
Rest of Europe	9.8	9.8	7.6
Extra European markets	1.2	2.0	2.9
E&P sales	**3.8**	**3.9**	**4.1**
Liquefaction plants:			
- Bontang (Indonesia)	0.7	0.6	0.6
- Point Fortin (Trinidad and Tobago)	0.6	0.4	0.5
- Bonny (Nigeria)	2.2	2.5	2.7
- Darwin (Australia)	0.3	0.4	0.3
	15.0	**15.7**	**14.6**

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 2012, the program for upgrading and improving flexibility of the combined cycle power plants progressed in accordance with the Company s developing plans.

In 2012, electricity sales (42.58 TWh) were directed to the free market (75%), the Italian power exchange (14%), industrial sites (8%) and others (3%). In 2012, electricity sales increased by 5.7% due to an increased client base thanks to effective marketing policies in spite of weak domestic demand.

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Power availability	2010	2011	2012
		(TWh)	
Power generation sold	25.63	25.23	25.67
Trading of electricity [(a)]	13.91	15.05	16.91
	39.54	**40.28**	**42.58**
Power sales by market			
Free market [(b)]	27.84	27.25	31.84
Italian Exchange for electricity	7.13	8.67	6.10
Industrial plants	3.21	3.23	3.30
Other [(a) (b)]	1.36	1.13	1.34
	39.54	**40.28**	**42.58**

(a) Include positive and negative imbalances.
(b) Network losses have been restated from other to free market.

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 2012, power production was 25.67 TWh, down 0.44 TWh, or 1.7% from 2011, mainly due to increased production at the Ferrara plant, offset in part by decreases at the Ferrera Erbognone and Ravenna plants.

As of December 31, 2012, installed operational capacity was 5.3 GW (5.3 GW as of December 31, 2011).

Power availability in 2012 was supported by the growth in electricity trading activities (up 1.86 TWh, or 12.4%) due to higher volumes traded on the Italian power exchange benefiting from lower purchase prices.

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 acknowledged as produced in cogeneration benefits from the exemption from the legal provision of buying green certificates. According to this legal provision, power producers has to input a certain percentage of energy from renewable sources in proportion to the energy produced from fossil-fuel or, as an alternate measure, to purchase green certificates. The recently enacted Legislative Decree No. 28/2011 provides for a gradual reduction of the share of electricity production currently covered by obligation of buying green certificates, until it is completely cancelled in 2015. Eni and other cogeneration producers are involved in a legal argument with 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, concerning the way of assessing energy acknowledged as produced in cogeneration. Position supported by GSE implies that producers have to buy a greater amount of green certificates because they are not allowed to assess the amount of electricity from cogeneration according to the AEEG s decision 42/02.

With a further administrative measure, 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 trend higher 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.

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

Site	Total installed capacity in 2012 [(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		2010	2011	2012
Purchases				
Natural gas	(mmCM)	5,154	5,008	5,206
Other fuels	(ktoe)	547	528	462
- of which steam cracking		*103*	*99*	*98*
Production				
Electricity	(TWh)	25.63	25.23	25.67
Steam	(ktonnes)	10,983	14,401	12,603
Installed generation capacity	(GW)	**5.3**	**5.3**	**5.3**

Infrastructures

Eni has transport rights on a large European network of integrated infrastructure for transporting natural gas, which links key consumption basins with the main producing areas (Russia, Algeria, Libya and the North Sea).

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

Eni owns capacity entitlements in an extensive network of international high pressure enabling the Company to import natural gas produced in Russia, Algeria, the North Sea, including the Netherlands and Norway, and Libya to Italy. The Company participates to both entities which own and operate the pipelines, the pipeline owners, and entities which manage transport rights, the carriers. For financial reporting purposes, such entities are either fully-consolidated or equity-accounted depending on the Company s interest or agreements with other shareholders.

The structure of the Company s interests in those entities has significantly changed in 2011 following the divestment of Eni s interests in importing pipelines of natural gas from Northern Europe (TENP and Transitgas) and Russia (TAG) and related carrier companies, as part of the agreements signed on September 29, 2010 with the European Commission to settle an antitrust proceeding related to alleged anti-competitive behavior in the natural gas market. In light of the strategic importance of the Austrian TAG pipeline to the supply of the Italian system, which transports gas from Russia to Italy, Eni divested its stake to an entity controlled by the Italian State. However, Eni retained its gas transport rights in the divested assets.

A description of the main international pipelines currently participated or operated by Eni is provided below.

The TTPC pipeline, 740-kilometer long, made up of two lines that are each 370-kilometer long with a transport capacity of 33.2 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 pipeline was recently upgraded by increasing compression capacity in order to enable transportation of an additional 6.5 BCM/y. The upgrade was finalized in 2008 and became fully-operational during 2009.

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 11 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 the shareholder agreement the minority shareholders including Eni have the right to leave the project in case certain future conditions are not satisfied.

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 a depressed one as management does not expect any meaningful improvement in the trading environment over the next four years of the industrial plan. 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. 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 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 convert the Venice plant into a "bio-refinery" to produce bio-fuels;
- to achieve energy efficiency initiatives and ensure higher rates of plant reliability;
- to rationalize logistic costs and implement other cost-saving measures;
- 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:

- strengthening our leadership in the Italian retail market leveraging on opportunities deriving from the liberalization process (i.e. rationalizing stations with low throughput, boosting full "iperself" mode and development of non-oil activities);
- preserving our customer base by effective marketing actions, rolling out our "eni" brand and service excellence;
- boosting margins by increasing the number of fully automated outlets and the contribution from non-oil products and services; and
- selectively growing our market share in European markets.

In the 2013-2016 period, we plan to make capital expenditures amounting to euro 2.4 billion carefully selecting capital projects. Management plans to invest approximately euro 1.7 billion to convert the Venice plant into a bio-refinery, upgrade the Company s best refineries mainly by completing and starting-up the EST (Eni Slurry Technology) project at the Sannazzaro unit which will upgrade the conversion capacity of the refinery, as well as improving 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.

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Supply

In 2012, a total of 62.21 mmtonnes of crude were purchased by the Refining & Marketing segment (59.02 mmtonnes in 2011), of which 26.92 mmtonnes from Eni s Exploration & Production segment, 24.95 mmtonnes on the spot market and 10.34 mmtonnes were purchased under long-term supply contracts with producing countries. Approximately 25% of crude purchased in 2012 came from Russia, 19% from West Africa, 12% from the North Sea, 10% from North Africa, 8% from the Middle East, 6% from Italy and 20% from other areas. In 2012, some 36.56 mmtonnes of crude purchased were marketed (down 4.46 mmtonnes from 2011, or 13.9%). In addition, 4.53 mmtonnes of intermediate products were purchased (4.26 mmtonnes in 2011) to be used as feedstock in conversion plants and 20.52 mmtonnes of refined products (15.85 mmtonnes in 2011) were purchased to be sold on markets outside Italy (17.24 mmtonnes) and on the domestic market (3.28 mmtonnes) as a complement to available production.

Refining

In 2012, Eni s refining system had total refinery capacity (balanced with conversion capacity) of approximately 38.3 mmtonnes (equal to 767 kBBL/d) and a conversion index of 61%. Conversion index let to evaluate 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 64% conversion index. In 2012, Eni s refineries throughputs in Italy and outside Italy was 30.01 mmtonnes.

The table below sets forth certain statistics regarding Eni s refineries as of December 31, 2012.

Refining system in 2012

	Ownership share (%)	Distillation capacity (total) (kBBL/d)	Distillation capacity (Eni s share) (kBBL/d)	Primary balanced refining capacity (Eni s share) (kBBL/d)	Conversion index [1] (%)	Fluid catalytic cracking - FCC [2] (kBBL/d)	Residue conversion (kBBL/d)	Go-Finer (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**	**64**	**69**	**42**	**37**	**29**	**89**	**46**	**61**	**73**
Italy													
Sannazzaro	100	223	223	190	59	34	12		29	29		75	88
Gela	100	129	129	100	142	35		37			46	33	42
Taranto	100	120	120	120	72		30			38		66	66
Livorno	100	106	106	84	11							76	96
Porto Marghera	100	107	107	80	20					22		44	59
Partially owned refineries [3]		**874**	**245**	**193**	**51**	**167**	**25**		**99**	**27**		**79**	**100**
Italy													
Milazzo	50	248	124	80	76	45	25		32			73	113
Germany													
Vohburg/Neustadt (Bayernoil)	20	215	43	41	36	49			43			92	96
Schwedt	8.33	231	19	19	42	49				27		101	104

Czech Republic													
Kralupy e Litvinov	32.4	180	58	53	30	24			24			75	83
Total refineries		**1,559**	**930**	**767**	**61**	**236**	**67**	**37**	**128**	**116**	**46**	**72**	**80**

(1) Stated in fluid catalytic cracking equivalent/topping (% by weight), based on 100% of balanced primary distillation capacity.

(2) 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.

(3) 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 59%. 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. The most important currently underway project is EST (Eni Slurry Technology) a conversion plant with a 23 kBBL/d capacity in order to process extra heavy crude with high sulphur content increasing middle distillates, reducing fuel oil. Start-up of this facility is scheduled by 2013. 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 2012 a total of 2.26 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 feedstocks 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 suphur 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.

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 will begin in the second quarter of 2013 and start bio-fuel production in 2014 and will be associated with a logistics center.

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 is 32.4% in Ceska Rafinerska, 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	**2010**	**2011**	**2012**
		(mmtonnes)	
ITALY			
Refinery throughputs			
At wholly-owned refineries	25.70	22.75	20.84
Less input on account of third parties	(0.50)	(0.49)	(0.47)
At affiliated refineries	4.36	4.74	4.52
Refinery throughputs on own account	**29.56**	**27.00**	**24.89**
Consumption and losses	(1.69)	(1.55)	(1.34)
Products available for sale	**27.87**	**25.45**	**23.55**
Purchases of refined products and change in inventories	4.24	3.22	3.35
Products transferred to operations outside Italy	(4.18)	(1.77)	(2.36)
Consumption for power generation	(0.92)	(0.89)	(0.75)
Sales of products	**27.01**	**26.01**	**23.79**
OUTSIDE ITALY			
Refinery throughputs on own account	**5.24**	**4.96**	**5.12**
Consumption and losses	(0.24)	(0.23)	(0.23)
Products available for sale	**5.00**	**4.73**	**4.89**
Purchases of finished products and change in inventories	10.61	12.51	17.29
Products transferred from Italian operations	4.18	1.77	2.36
Sales of products	**19.79**	**19.01**	**24.54**
Refinery throughputs on own account	**34.80**	**31.96**	**30.01**
of which: refinery throughputs of equity crude on own account	*5.02*	*6.54*	*6.39*
Total sales of refined products	**46.80**	**45.02**	**48.33**
Crude oil sales	**36.17**	**32.10**	**36.56**
TOTAL SALES	**82.97**	**77.12**	**84.89**

In 2012, refining throughput was 30.01 mmtonnes, decreased of 1.95 mmtonnes, or 6.1% versus 2011. Processed volumes in Italy, decreased of 7.8% compared to 2011, due to scheduled shutdowns in order to mitigate negative scenario impact mainly in Gela (shutdown of two production lines since June 2012) and Taranto (TSTC shutdown). Throughput reduction is partly offset by higher volumes processed in Venice (shutdown from November 2011 to April 2012). Outside Italy, Eni s refining throughputs increased by 3.2% (approximately 160 ktonnes) in particular in CRC for the Litvinov refinery shutdown in 2011. Wholly-owned refineries throughput is 20.84 mmtonnes, decreased of 1.91 mmtonnes (down 8.4%) versus 2011 with a refinery utilization rate of 73%, in reduction versus 2011 according to negative scenario. Approximately 22.8% was supplied by segment representing a 0.5 percentage point increase from 2011 (22.3%).

Eni s Exploration & Production segment supplied approximately 22.8% of crudes, up 0.5% versus 2011.

Logistics

Eni is a primary operator in storage and transport of petroleum products in Italy with its logistical integrated infrastructure consisting of 20 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 1,447-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	2010	2011	2012
		(mmtonnes)	
Italy			
Retail	8.63	8.36	7.83
Wholesale	9.45	9.36	8.62
	18.08	**17.72**	**16.45**
Petrochemicals	1.72	1.71	1.26
Other sales	7.21	6.58	6.08
Total	**27.01**	**26.01**	**23.79**
Outside Italy			
Retail	3.10	3.01	3.04
Wholesale	4.30	4.27	4.38
	7.40	**7.28**	**7.42**
Other sales	12.39	11.73	17.12
Total	**19.79**	**19.01**	**24.54**
TOTAL SALES	**46.80**	**45.02**	**48.33**

In 2012, sales volumes of refined products (48.33 mmtonnes) increased by 3.31 mmtonnes from 2011, up 7.4%, due mainly to increased volumes sold to oil companies and traders outside Italy.

Retail sales in Italy

In 2012, retail sales in Italy of 7.83 mmtonnes decreased by approximately 530 ktonnes, down 6.3%, from 2011 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 (1,976 kliters) decreased by approximately 197 kliters from 2011. Eni s retail market share for 2012 was 31.2%, up 0.7 percentage points from 2011.

At December 31, 2012, Eni s retail network in Italy consisted of 4,780 service stations, 79 more than at December 31, 2011 (4,701 service stations), resulting from the positive balance of acquisitions/releases of lease concessions (92 units) and the opening of new service stations (10 units), partly offset by the closing of service stations with low throughput (23 units).

In 2012, sales of premium fuels (fuels of the "Eni Blu+" line with high performance and lower environmental impact) were also affected by the decline in domestic consumption and were lower than the previous year. In particular, sales of Eni bludiesel+ amounted to approximately 292 ktonnes (approximately 350 mmliters) with a decline of approximately 201 ktonnes from 2011 and represented 6% of volumes of gasoil marketed by Eni s retail network. At December 31, 2012, service stations marketing BluDiesel+ totaled 4,123 units (4,130 at 2011 year-end) covering approximately 86% of Eni s network. Retail sales of BluSuper+ amounted to 35 ktonnes (approximately 47 mmliters), decreasing by 27 ktonnes from 2011, and covered 1.5% of gasoline sales on Eni s retail network (down 0.9% from a year ago). At December 31, 2012, service stations marketing BluSuper+ totaled 2,505 units (2,703 at December 31, 2011), covering approximately 52% of Eni s network.

Within the initiatives aimed to spur consumption in a negative economic scenario and create sounder customer relationships, Eni launched two relevant campaigns: (i) in the summer of 2012 for twelve weekends in Eni stations the "riparti con eni" initiative provided customers in the hyperself mode of service an exceptionally lower price equal all over the Country; and (ii) the launch of a new "loyalty card", consisting in reloadable, prepaid and credit card versions, through which customers can accumulate many more points in the Eni and Agip branded service stations that can be used for all daily purchases made outside of the Eni network in over 30 million stores.

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, Austria and Eastern Europe (e.g. Czech Republic) leveraging on the synergies ensured by the proximity of these markets to Eni s production and logistic facilities.

In 2012, retail sales of refined products marketed in the rest of Europe (3.04 mmtonnes) were basically stable (up 1%). Volume additions in Austria and Switzerland reflecting successful commercial policies were almost completely offset by lower sales in Eastern Europe due to declining demand.

At December 31, 2012, Eni s retail network in the rest of Europe consisted of 1,604 service stations, an increase of 18 units from December 31, 2011 (1,586 service stations). The network evolution was as follows: (i) the closing of 28 low throughput service stations mainly in Austria and France; (ii) the positive balance of acquisitions/releases of lease concessions (33 units) in particular in Austria; (iii) the purchase of 11 service stations, in particular in Austria; and (iv) the opening of 2 new outlets. Average throughput (2,319 kliters) increased by 20 kliters from 2011 (2,299 kliters).

The key markets of Eni s presence are: Austria with a 11.7% market share, Hungary with 11.9%, Czech Republic with 10.8%, Slovakia with 9.7%, Switzerland with 7.1% 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 1,083 service stations (Eni owned network), of which 320 are in Germany, 208 in Austria and 135 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 and articulated in local marketing offices and a network of agents and concessionaires.

In 2012, sales volumes on wholesale markets in Italy (8.62 mmtonnes) declined by approximately 740 ktonnes, down 7.9%, mainly due declining sales of gasoline and gasoil related to a decline in demand from transports and industrial customers due to a generalized slowdown and lower jet fuel sales related to declining demand. Bitumen sales increased due increased product availability of Eni products related to downtime in competing refineries, in particular in the final part of the year. Average market share in 2012 was 29.5% (28.6% in 2011). Supplies of feedstock to the petrochemical industry (1.26 mmtonnes) dropped from 2011 (down 450 ktonnes) due to lower demand from industrial customers. Wholesale sales in the rest of Europe of approximately 3.96 mmtonnes increased by 3.1% from 2011 due to increased sales in Switzerland, the Czech Republic, Slovenia and France. Sales declined in Hungary, Austria and Germany. Other sales (23.20 mmtonnes) increased by 4.89 mmtonnes, or 27%, mainly due to higher sales volumes to oil companies.

Eni also markets jet fuel directly at 45 airports, of which 26 are in Italy. In 2012, 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 2012, marine fuel sales were 1.75 mmtonnes (1.67 mmtonnes in Italy).

LPG

In Italy, Eni is leader in LPG production, marketing and sale with 614 ktonnes sold for heating and automotive use equal to a 19.8% market share. An additional 206 ktonnes of LPG were marketed through other channels mainly to oil companies and traders. LPG activities in Italy are supported by direct production,