ENI SPA
Form 20-F
April 26, 2010

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, 2009

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)

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

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

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

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

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes No

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

Yes No

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

Indicate by check mark whether the registrant have submitted electronically and posted on their corporate Web sites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).*

Yes No

* This requirement does not apply to the registrants until their fiscal year ending December 31, 2011.

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 Qualitative and Quantitative 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 www.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.
Contingent resources	Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies.
Conversion capacity	Maximum amount of feedstock that can be processed in certain dedicated facilities of a refinery to obtain finished products. Conversion facilities include catalytic crackers, hydrocrackers, visbreaking units, and coking units.

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Conversion index	Ratio of capacity of conversion facilities to primary distillation capacity. The higher the ratio, the higher is the capacity of a refinery to obtain high value products from the heavy residue of primary distillation.
Deep waters	Waters deeper than 200 meters.
Development	Drilling and other post-exploration activities aimed at the production of oil and gas.
Enhanced recovery	Techniques used to increase or stretch over time the production of wells.
EPC	Engineering, Procurement and Construction.
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.

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Production Sharing Agreement ("PSA")	Contract in use in African, Middle Eastern, Far Eastern and Latin American countries, among others, regulating relationships between states and oil companies with regard to the exploration and production of hydrocarbons. The mineral right is awarded to the national oil company jointly with the foreign oil company that has an exclusive right to perform exploration, development and production activities and can enter into agreements with other local or international entities. In this type of contract the national oil company assigns to the international contractor the task of performing exploration and production with the contractor s equipment and financial resources. Exploration risks are borne by the contractor and production is divided into two portions: "cost oil" is used to recover costs borne by the contractor and "profit oil" is divided between the contractor and the national company according to variable schemes and represents the profit deriving from exploration and production. Further terms and conditions of these contracts may vary from country to country.
Proved reserves	Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. Reserves are classified as either developed and undeveloped. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.
Reserves	Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.
Reserve life index	Ratio between the amount of proved reserves at the end of the year and total production for the year.

Reserve replacement ratio	Measure of the reserves produced replaced by proved reserves. Indicates the company s ability to add new reserves through exploration and purchase of property. A rate higher than 100% indicates that more reserves were added than produced in the period. The ratio should be averaged on a three-year period in order to reduce the distortion deriving from the purchase of proved property, the revision of previous estimates, enhanced recovery, improvement in recovery rates and changes in the amount of reserves in PSAs due to changes in international oil prices.
Ship-or-pay	Clause included in natural gas transportation contracts according to which the customer is requested to pay for the transportation of gas whether or not the gas is actually transported.
Strategic Storage	According to Legislative Decree No. 164/2000, these are volumes required for covering lack or reduction of supplies from extra-European sources or crises in the natural gas system.

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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.

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	= 5,742 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 0.00615 barrels of oil equivalent	
1 kilometer	= approximately 0.62 miles	
1 short ton	= 0.907 tonnes	= 2,000 pounds
1 long ton	= 1.016 tonnes	= 2,240 pounds
1 tonne	= 1 metric ton	= 1,000 kilograms = approximately 2,205 pounds
1 tonne of crude oil	= 1 metric ton of crude oil	= approximately 7.3 barrels of crude oil (assuming an API gravity of 34 degrees)

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PART I

Item 1. IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISORS

NOT APPLICABLE

Item 2. OFFER STATISTICS AND EXPECTED TIMETABLE

NOT APPLICABLE

Item 3. KEY INFORMATION

Selected Financial Information

The Consolidated Financial Statements of Eni have been prepared in accordance with IFRS issued by the International Accounting Standards Board (IASB). The tables below show Eni selected historical financial data prepared in accordance with IFRS as of and for the years ended December 31, 2005, 2006, 2007, 2008 and 2009. 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.

	Year ended December 31,				
	2005	2006	2007	2008	2009
	(euro million except data per share and per ADR)				
CONSOLIDATED PROFIT STATEMENT DATA					
Net sales from operations	73,728	86,105	87,204	108,082	83,227
Operating profit by segment [(1)]					
Exploration & Production	12,592	15,580	13,433	16,239	9,120
Gas & Power	3,321	3,802	4,465	4,030	3,687
Refining & Marketing	1,857	319	686	(988)	(102)
Petrochemicals	202	172	100	(845)	(675)
Engineering & Construction	307	505	837	1,045	881
Other activities	(934)	(622)	(444)	(346)	(382)
Corporate and financial companies	(377)	(296)	(312)	(743)	(474)
Impact of unrealized intragroup profit elimination [(2)]	(141)	(133)	(26)	125	
Operating profit	16,827	19,327	18,739	18,517	12,055
Net profit attributable to Eni	8,788	9,217	10,011	8,825	4,367
Data per ordinary share (euro) [(3)]					
Operating profit:					
- basic	4.48	5.23	5.11	5.09	3.33

- diluted	4.47	5.22	5.11	5.09	3.33
Net profit attributable to Eni basic and diluted	2.34	2.49	2.73	2.43	1.21
Data per ADR ($) [(3)] [(4)]					
Operating profit:					
- basic	11.14	13.13	14.01	14.97	9.27
- diluted	11.12	13.12	14.00	14.97	9.27
Net profit attributable to Eni basic and diluted	5.82	6.26	7.48	7.14	3.36

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	As of December 31,				
	2005	**2006**	**2007**	**2008**	**2009**
	(euro million except number of shares and dividend information)				
CONSOLIDATED BALANCE SHEET DATA					
Total assets	83,850	88,312	101,460	116,673	117,529
Short-term and long-term debt	12,998	11,699	19,830	20,837	24,800
Capital stock issued	4,005	4,005	4,005	4,005	4,005
Minority interest	2,349	2,170	2,439	4,074	3,978
Shareholders equity - Eni share	36,868	39,029	40,428	44,436	46,073
Capital expenditures	7,414	7,833	10,593	14,562	13,695
Weighted average number of ordinary shares outstanding (fully diluted - shares million)	3,763	3,701	3,668	3,639	3,622
Dividend per share (euro)	1.10	1.25	1.30	1.30	1.00
Dividend per ADR ($) [3]	2.73	3.24	3.74	3.72	2.91

(1) From 2009, gains and losses on non-hedging commodity derivative instruments, including both fair value re-measurement and settled transactions are reported as items of operating profit. Also results of the gas storage business are reported within the Gas & Power segment reporting unit, as part of the regulated businesses results, following the restructuring of Eni s regulated gas businesses in Italy. In past years, results of the gas storage business were reported within the Exploration & Production segment. Data for the years ended December 31, 2008 and 2007 have been restated. Prior year data have not been restated.

(2) This item mainly concerned 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) Euro per share or U.S. dollars per American Depositary Receipt (ADR), as the case may be. From 2006, one ADR represents two Eni shares. Previously, one ADR was equivalent to five Eni shares. Data per ADR for the year 2005 have been recalculated accordingly.

(4) 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/U.S. $ 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 2005 through 2008 have been 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. Eni started to pay an interim dividend in 2005. The dividend for 2009 was converted at the Noon Buying Rate recorded on the payment date of the interim dividend (euro 0.50 per share) which occurred on September 24, 2009. The balance of euro 0.50 per share payable on May 24 and May 27, 2010 for the holders of the Eni share and the ADR, respectively, was translated at the Noon Buying Rate as recorded on December 31, 2009. On April 9, 2010 the Noon Buying Rate was $1.35 per euro 1.00.

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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, 2005, 2006, 2007, 2008 and 2009. 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 or cost method of accounting.

	Year ended December 31,				
	2005	2006	2007	2008	2009
Proved reserves of liquids of consolidated subsidiaries at period end (mmBBL)	3,748	3,457	3,127	3,243	3,377
of which developed	*2,331*	*2,126*	*1,953*	*2,009*	*2,001*
Proved reserves of liquids of equity-accounted entities at period end (mmBBL)	25	24	142	142	86
of which developed	*19*	*18*	*26*	*33*	*34*
Proved reserves of natural gas of consolidated subsidiaries at period end (BCF)	17,501	16,897	16,549	17,214	16,262
of which developed	*11,159*	*10,949*	*10,967*	*11,138*	*11,650*
Proved reserves of natural gas of equity-accounted entities at period end (BCF)	90	68	3,022	3,015	1,588
of which developed	*70*	*48*	*428*	*420*	*234*
Proved reserves of hydrocarbons of consolidated subsidiaries in mmBOE at period end (1)	6,796	6,400	6,010	6,242	6,209
of which developed	*4,275*	*4,032*	*3,862*	*3,948*	*4,030*
Proved reserves of hydrocarbons of equity-accounted entities in mmBOE at period end (a)	41	36	668	666	362
of which developed	*31*	*27*	*101*	*107*	*74*
Reserve replacement ratio (2)	43	38	38	136	95
Average daily production of liquids (KBBL/d)	1,111	1,079	1,020	1,026	1,007
Average daily production of natural gas available for sale (mmCF/d) (3)	3,344	3,679	3,819	4,143	4,074
Average daily production of hydrocarbons available for sale (KBOE/d) (3)	1,693	1,720	1,684	1,748	1,716
Hydrocarbon production sold (mmBOE)	614.9	625.1	611.4	632.0	622.8
Oil and gas production costs per BOE (4)	5.59	5.79	6.90	7.77	7.49
Profit per barrel of oil equivalent (5)	12.20	14.97	14.03	15.80	7.96

(a) Mainly refers to Eni s share of proved reserves relating to three Russian companies purchased in 2007 and participated by the joint venture OOO SeverEnergia, owned by Eni (60%) and its Italian partner Enel (40%). On September 23, 2009 the two partners divested a 51% stake in the venture to Gazprom in line with the call option arrangement.

(1) Includes approximately 760, 754, 749, 746 and 769 BCF of natural gas held in storage in Italy as of December 31, 2005, 2006, 2007, 2008 and 2009, respectively.

(2) Referred to Eni s subsidiaries. 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) Natural gas production volumes exclude gas consumed in operations (251, 286, 296, 281 and 300 mmCF/d in 2005, 2006, 2007, 2008 and 2009, respectively).

(4) Expressed in U.S. dollars. Consists of production costs (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, divided by actual sold production, in each case prepared in accordance with IFRS to meet ongoing U.S. reporting obligations. 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. Includes results of operations of joint ventures and other equity-accounted entities which results were immaterial.

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Selected Operating Information *continued*

	Year ended December 31,				
	2005	2006	2007	2008	2009
Sales of natural gas to third parties (6)	77.08	79.63	78.75	83.69	83.79
Natural gas consumed by Eni (6)	5.54	6.13	6.08	5.63	5.81
Sales of natural gas of affiliates (Eni s share) (6)	7.08	7.65	8.74	8.91	7.95
Total sales and own consumption of natural gas of the Gas & Power segment (6)	89.70	93.41	93.57	98.23	97.55
E&P natural gas sales in Europe and in the Gulf of Mexico (6) (7)	4.51	4.69	5.39	6.00	6.17
Worldwide natural gas sales (6)	94.21	98.10	98.96	104.23	103.72
Transport of natural gas for third parties in Italy (6)	30.22	30.90	30.89	33.84	37.27
Length of natural gas transport network in Italy at period end (8)	30.7	30.9	31.1	31.5	31.5
Electricity sold (9)	27.56	31.03	33.19	29.93	33.96
Refinery throughputs (10)	36.68	36.27	37.15	35.84	34.55
Balanced capacity of wholly-owned refineries (11)	524	534	544	544	554
Retail sales (in Italy and rest of Europe) (10)	13.72	12.48	11.80	12.03	12.02
Number of service stations at period end (in Italy and rest of Europe)	6,282	6,294	6,441	5,956	5,986
Average throughput per service station (in Italy and rest of Europe) (12)	2,479	2,470	2,486	2,502	2,477
Petrochemical production (10)	7.28	7.07	8.80	7.37	6.52
Engineering & Construction order backlog at period end (13)	10,122	13,191	15,390	19,105	18,730
Employees at period end (units)	72,258	73,572	75,862	78,880	78,417

(6) Expressed in BCM.

(7) From 2006, also includes E&P sales of volumes of natural gas produced in the Gulf of Mexico.

(8) Expressed in thousand kilometers.

(9) Expressed in TWh.

(10) Expressed in mmtonnes.

(11) Expressed in KBBL/d.

(12) Expressed in thousand liters per day.

(13) The sum of the order backlog of Saipem SpA and Snamprogetti SpA, expressed in euro million.

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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,				
2005	1.35	1.17	1.24	1.18
2006	1.33	1.19	1.26	1.32
2007	1.49	1.29	1.37	1.46
2008	1.60	1.24	1.47	1.39
2009	1.51	1.25	1.39	1.43

(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)		
November 2009	1.51	1.47	1.50
December 2009	1.51	1.42	1.43
January 2010	1.45	1.39	1.39
February 2010	1.40	1.35	1.37
March 2010	1.38	1.33	1.35
April 2010 (through April 9, 2010)	1.36	1.34	1.35

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 9, 2010 was $1.35 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 competition from other oil and natural gas companies in all areas of its operations.

In the Exploration & Production business, Eni faces competition from both international oil companies and state-owned oil companies in a number of geographic markets for obtaining exploration and development rights, and developing and applying new technologies to maximize hydrocarbon recovery. Furthermore, Eni may face a competitive disadvantage in many of these markets 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 or to apply and develop new technologies, its growth prospects and future results of operations and cash flows may be adversely affected.

In its natural gas business, Eni faces increasingly strong competition on both the Italian market and the European market driven by weak prospects for demand growth over the short and medium-term, and increasing gas availability on the marketplace. Significant investments to expand import capacity to Europe via pipeline and LNG have been made by a number of operators including Eni, in recent years. At the same time, forecasts for demand growth in Europe have been overestimated and the economic downturn has caused a much larger-than-anticipated demand contraction. As natural gas is a commodity, gas oversupply may lead suppliers to compete more aggressively on pricing thus leading to lower gas margins for the whole sector. The condition of oversupply is signaled by current trends in differentials between spot price and long-term prices for natural gas, whereby the former no longer appear to be correlated to oil-linked formulas that determine gas prices in long-term supply contracts. Management believes that a better balance between demand and supply on the European market will not be achieved until 2013 at the earliest. The circumstances described above might negatively affect the Company s future results of operations and cash flow 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. In Italy, competitive pressures are fostered by the liberalization of the Italian natural gas market that was mandated by Legislative Decree No. 164/2000 which provides for, among other things, the opening of the Italian market to competition, limitations to the size of gas companies relatively to the market and third party access to infrastructures, and the power of the Italian Authority for Electricity and Gas to regulate natural gas pricing in the residential sector and access to infrastructures. Increasingly high levels of competition in the Italian natural gas market may lead to lower natural gas selling margins (see below). Outside of Italy, particularly in Europe, Eni 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. Furthermore, a number of large clients, particularly electricity producers, in both the domestic market and other European markets are planning to enter the supply market of natural gas. 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 national and other European markets for natural gas and reduce Eni s operating profit.

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. The Company expects in the near future increasing competition due to the weak GDP growth expected in Italy and Europe over the next one to two years causing outside players to place excess production on the Italian market.

In retail marketing of refined products both in and outside Italy, 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. Once established, Eni s service stations compete primarily on the basis of pricing, services and availability of non-petroleum products. In Italy, there is pressure from political and administrative entities, including the Italian Antitrust Authority, to increase levels of competition in the retail marketing of fuels. Eni expects developments on this issue to further increase pressure on selling margins in the retail marketing of fuels.

In the Petrochemical segment we face intense competition from well-established international players and state-owned petrochemical companies, particularly in the most commoditized market segments. Many of those competitors may benefit from cost advantages due to larger scale, looser environmental regulations, availability of oil-based feedstock, and more favorable location and proximity to end-markets. Excess capacity and sluggish economic growth may exacerbate competitive pressures. The Company expects continuing margin pressures in the foreseeable future as a result of those trends.

Competition in the oilfield services, construction and engineering industries is primarily based on technical expertise, quality and number of services and availability of technologically advanced facilities (for example, vessels for offshore construction). Lower oil prices could result in lower margins and lower demand for oil services.

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.

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 entails particular economic risks. It is subject to natural hazards and other uncertainties including those relating to the physical characteristics of oil and natural gas fields. 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, environmental protection measures, control over the development and abandonment of fields and installations, and restrictions on production. 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.

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Exploratory drilling efforts may not be successful

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 are often uncertain, and drilling operations may be unsuccessful as a result of a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or fires, blow-outs and various forms of accidents, marine risks such as collisions and adverse weather conditions and shortages or delays in the delivery of equipment. Exploring or drilling in offshore areas, particularly in deep waters, is generally more complex and riskier than in onshore areas; the same is true for exploratory activity in remote areas or in challenging environmental conditions such as those we are experiencing in the Caspian region or Alaska. In addition, we may fail to secure a market for the quantities of oil and gas that are discovered, for example because there is no economic or practicable means to transport such quantities to the final market. 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 invest significant capital expenditures in executing high risk exploration projects, it is likely that Eni will incur significant exploration and dry hole expenses in future years. High risk exploration projects include projects executed in deep and ultra-deep offshore and in new areas where the Company lacks installed production facilities. Particularly, Eni plans to explore for oil and gas offshore, frequently in deep waters or at deep drilling depths, where operations are more difficult and costly than on land or at shallower depths and in shallower waters. Deep water operations generally require a significant amount of time between a discovery and the time that Eni can produce and market the oil or gas, increasing both the operational and financial risks associated with these activities. The Company plans to conduct risky exploration projects offshore in the Gulf of Mexico, Libya, Angola, Nigeria, Norway and Indonesia. In 2009, the Company invested euro 1.23 billion in executing exploration projects and it plans to spend approximately euro 1.17 billion per annum on average over the next four years.

Furthermore, shortage of deep water rigs 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.

Development projects bear significant operational risks which may adversely affect actual returns on such projects

Eni is involved in a number of development projects for the production of hydrocarbon reserves. Certain projects are planned to develop reserves in high risk areas, particularly offshore and in remote and hostile environments. Eni s future results of operations and liquidity rely upon its ability to 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, suppliers, customers or others including, for example, Eni s ability to negotiate favorable long-term contracts with customers; 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. Furthermore, projects executed with partners and co-venturers reduce the ability of the Company to manage risks and costs, and Eni could have limited influence over and control of the operations, behaviors and performance of its partners;
- timely issuance of permits and licenses by government agencies;
- the Company s relative size compared to its main competitors which may prevent it from affording opportunities to participate 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;

changes in operating conditions and costs. In recent years prior to 2009, we experienced a sharp rise in procurement costs and costs for leasing third party equipment or purchase services such as drilling rigs as a result of industry-wide cost inflation, resulting in cost overruns. Notwithstanding the global economic downturn, costs for industry-specific services and materials and equipment decreased less-than-anticipated or actually increased compared to the previous year as oil prices recovered fairly quickly from the lows seen at the end of 2008 and beginning of 2009. The Company expects that costs in its upstream operations will remain at the same level or post a slightly rising trend in future years compared to the level seen in 2009;

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.

Furthermore, deep waters and other hostile environments, where the majority of Eni s planned and existing development projects are located, can exacerbate these problems. Delays and differences between scheduled and actual timing of critical events, as well as cost overruns may adversely affect completion, the total amount of expenditures to be incurred and start-up of production from such projects and, consequently, actual returns. 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 which may be substantially lower with respect to prices assumed when the investment decision was actually made, leading to lower rates of return. For example, we have experienced increased budgeted expenditures and a substantial delay in the scheduling of production start-up at the Kashagan field, where development is ongoing. Specifically, based on the new plan that was sanctioned by relevant Kazakh Authorities in 2008, the Company increased estimated expenditures to develop the phase 1 of the project from an original amount of U.S. $10.3 billion (Eni s interest being at the time 18.52%) subject to adjustment to take into account cost inflation up to 2007 to a revised expenditure budget amounting to U.S. $32.2 billion (excluding general and administrative expenses), of which U.S. $25.4 billion related to the original scope of work of phase 1 (including tranches 1 and 2). Eni will fund those investments in proportion to its participating interest of 16.81%. First oil is expected late in 2012 based on the new plan, while the original development plan that was filed with Kazakh Authorities in 2004 forecast first oil in 2008. The change in production start-up and the relevant cost increase over the original budget were driven by a number of factors including depreciation of the U.S. dollar versus the euro and other currencies; cost price 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. See "Item 4 Exploration & Production Caspian Sea" for a full description of the material terms of the Kashagan project.

In 2009, we experienced significant cost overruns to develop our operated Blacktip project, offshore Australia, leading us to record an impairment charge of euro 153 million to take into account the reduced project profitability.

See "Item 4 Business Overview Exploration & Production". In the event the Company is unable to develop and operate major projects as planned, particularly if the Company fails to exercise tight control over costs and time schedules, it could incur significant impairment charges associated with costs overruns and project delays in future years with an adverse effect on our results of operations and liquidity.

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 and new discoveries, the Company s reserve replacement is also affected by the entitlement mechanism in its Production Sharing Agreements and similar contractual schemes. In accordance with such contracts, Eni is entitled to a portion of a field s reserves, the sale of which is intended to cover expenditures incurred by the Company to develop and operate the field. The higher the reference prices for Brent crude oil used to estimate Eni s proved reserves, the lower the number of barrels necessary to recover the same amount of expenditures. In 2009, the Company s reserve replacement was negatively affected by reduced entitlements in its PSAs for an estimated amount of 100 mmBOE, which was the principal factor leading to a reserve replacement ratio of 95% for Eni s subsidiaries (meaning that the Company replaced less reserves than those produced). See "Item 4 Business Overview Exploration & Production". 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. An inability to replace reserves could adversely impact future production levels and growth prospects, thus negatively affecting Eni s future results of operations and financial condition.

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. Eni generally does not hedge its exposure 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 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; in the current economic downturn we have experienced a significant reduction in worldwide demand for crude oil and in the European gas demand which have negatively impacted crude oil and natural gas prices;
(iv) prices and availability of alternative sources of energy;
(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. Such factors can also affect the prices of natural gas because natural gas prices for the major part of our supplies are typically indexed to the prices of crude oil and certain refined petroleum products. Lower crude oil prices have an adverse impact on Eni s results of operations and cash flow. In 2009, the average price of the Brent barrel decreased by 36.6% compared to 2008 in dollar terms; gas prices experienced an even sharper decline driven by weak spot prices due to large gas availability on the marketplace. Spot prices of gas at the Henry Hub market, which is a highly liquid spot market in the U.S. declined by 55.4% in dollar terms. As a consequence of those trends in the market benchmarks, realized prices of the Company s equity oil and gas decreased by 31.2% on average in dollar terms. Reduced prices negatively impacted the operating profit reported by the Exploration & Production segment which was down by 43.8%, or euro 7,119 million from a year ago.

Furthermore, lower oil and gas prices over prolonged periods may also adversely affect Eni s results of operations and cash flow 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 impairments charges.

Uncertainties in Estimates of Oil and Natural Gas Reserves

Numerous 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 because the estimates of reserves are based on prices and costs existing as of the date when those estimates are made. In particular the reserves 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.

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

In recent years, Eni has experienced adverse changes in tax regimes applicable to oil and gas operations in Italy and in a number of countries where the Company conducts its upstream operations. In 2009 management estimates that the tax rate of the Company s Exploration & Production segment was approximately 60%, representing an increase of an estimated 4% compared to 2008 as a result of new mechanisms that were implemented to calculate income taxes currently payable in a number of non OECD countries, namely Libya. See "Item 5 Operating and Financial Review and Prospects Taxation for the year". Management believes that adverse changes are possible in the tax regimes of any country in which Eni conducts its oil and gas operations, regardless of the level of stability of the political and legislative framework in each country. See "Political considerations" below. In recent years, developments in the regulatory framework, mainly regarding tax issues, have been implemented or announced also in EU countries and in North America. In 2008, Italy enacted new tax rules that increased the statutory tax rate applicable to energy companies with annual turnover in excess of euro 25 million by 5.5%, thus reversing a reduction in the statutory tax rate of the same amount that was enacted the previous year. In 2009, the above mentioned 5.5% supplemental tax rate was increased by another percentage point to 6.5% thus bringing the Italian statutory tax-rate to 34%. Also in 2009, the Italian Parliament enacted a supplemental tax rate of 4% that has to be applied to profit before income taxes reported by the parent company Eni SpA associated with a treaty between Italy and Libya. This tax rate increased tax payables by approximately euro 239 million for the full year 2009.

Adverse changes in the tax rate applicable to the Group profit before income taxes would have a negative impact on Eni s future results of operations and cash flows. Furthermore, the marginal tax rate in the oil and gas industry tends to increase in correlation with higher oil prices which could make it 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.

Political Considerations

A substantial portion of our oil and gas reserves and gas supplies are located in politically, socially and economically unstable countries where we are exposed to material disruptions to our operations

Substantial portions of Eni s hydrocarbon reserves are located in countries outside the EU and North America, some of which may be politically or economically less stable than EU or North American countries. As of December 31, 2009, approximately 80% of Eni s proved hydrocarbon reserves were located in such countries. Similarly, a substantial portion of Eni s natural gas supplies comes from countries outside the EU and North America. In 2009, approximately 60% of Eni s supplies of natural gas came from such countries. See "Item 4 Gas & Power Natural Gas Supplies". Adverse political, social and economic developments in any of those countries may 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. Particularly 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 titles 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. For example, Sonatrach, the Algerian national oil company, is seeking to modify the contractual terms of certain PSAs in which Eni is party to achieve a redistribution of the tax burden of such PSAs. Sonatrach alleges that it is currently bearing part of the tax burden attributable to Eni following the enactment of certain modifications to the country s tax regime. In case those negotiations result in a negative outcome for Eni, the future profitability of certain of Eni s PSAs in Algeria will be reduced. For more information on this matter see "Item 4 Exploration & Production Algeria". Furthermore, in 2009 we recorded a loss amounting to euro 205 million on certain receivables versus local co-venturers as certain contractual clauses relating to cost recovery were unfavorably interpreted and applied. As of the balance sheet date receivables for euro 461 million relating to cost recovery under a petroleum contract in a non-OECD country were the subject of arbitration proceedings. Similar issues are also being experienced in Kazakhstan where there is a dispute in relation to certain unresolved items of expenditure incurred by the operating company Karachaganak Petroleum Operating BV which has led to the Kazakh Authorities making certain claims against the company on the base of audits performed relating to prior years 2003-2006. Parties are negotiating in order to settle the dispute;

(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 have been experiencing continuing social unrest in Nigeria leading to a number of disruptions at certain Eni oil producing facilities in the country. As a consequence, our oil and gas production in the country has yet to return to normal production levels. In 2009, security problems have continued to impact our operations. See "Item 4 Exploration & Production".

In 2008 we incurred asset impairments for euro 989 million in our Exploration & Production business mainly driven by changes in contractual arrangements and regulatory provisions and environmental obligations leading the

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Company to reassess the recoverable amounts of a number of its oil and gas properties, particularly in Turkmenistan.

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.

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 of America impose sanctions on this country and may lead to the imposition of sanctions on any persons doing business in this country or with Iranian counterparties.

Under the Iran Sanctions Act of 1996 (as amended, "ISA"), which implements sanctions against Iran with the objective of denying it the ability to support acts of international terrorism and fund the development or acquisition of weapons of mass destruction, upon receipt by the U.S. authorities of information indicating potential violation of this act, the President of the United States is authorized to start an investigation aiming at possibly imposing sanctions from a six-sanction menu against any person found in particular to have knowingly made investments of U.S. $20 million or more in any twelve-month period, contributing directly and significantly to the enhancement of Iran s ability to develop its hydrocarbons resources. Furthermore, the ISA contemplates sanctions to be imposed by the President of the United States against any persons that knowingly contribute to certain military programs of Iran, effective on June 6, 2006. Eni cannot predict interpretations of, or the implementation policy of the U.S. Government under ISA with respect to Eni s current or future activities in Iran or other areas. Eni has incurred capital expenditures in excess of U.S. $20 million in Iran in each of the last 10 years. Management may decide to invest amounts in excess of $20 million per year in the country in the future. No sanctions have been imposed to date on Eni s activities in the country. Eni s current activities in Iran are primarily limited to carrying out residual activities relating to certain buy-back contracts it entered into in 2000 and 2001. Specifically, activities are progressing to hand over operatorship of the Darquain oilfield to the local partners as development activities were concluded at this field in 2009. Darquain remained the sole activity operated by Eni in the Country. Regarding another project that was handed over in past years, Eni s involvement consists essentially in being reimbursed for its past investments. In 2009, Eni s production in Iran was 35 KBOE/d, approximately 2% of the Group s total production. Eni does not believe that its activities in Iran have a material impact on the Group s results.

Adding to Eni s risks arising from this matter, a bill to amend and extend the extra-territorial reach of the economic sanctions imposed by the United States with respect to Iran has been passed by the U.S. House of Representatives and may lead to the passage of new laws in this area. Iran continues to be designated by the U.S. State Department as a State sponsoring terrorism. For a description of Eni s operations in Iran see "Item 4 Information on the Company Exploration & Production Rest of Asia". It is possible that in future years Eni s activities in Iran may be sanctioned under relevant U.S. legislation.

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. These policies could adversely impact or limit investment by certain investors in our securities and so possibly impact adversely our share price.

Cyclicality of the Petrochemical Industry

The petrochemical industry is subject to cyclical fluctuations in demand in response to economic cycles, with consequential effects on prices and profitability exacerbated by the highly competitive environment of this industry. Eni s petrochemical operations have been in the past and may be adversely affected in the future by worldwide economic slowdowns, intense competitive pressures and excess installed production capacity. Furthermore, Eni s petrochemical operations face increasing competition from Asian companies and national oil companies petrochemical divisions which can leverage on long-term competitive advantages in terms of lower operating costs and feedstock purchase costs. Particularly, Eni s petrochemical operations are located mainly in Italy and Western Europe where the regulatory framework and public environmental sensitivity are generally more stringent than in other countries, especially Far East countries, resulting in higher operating costs of our petrochemical operation compared to the Company s Asiatic competitors due to the need to comply with applicable laws and regulations in environmental and other related matters. Additionally, our petrochemical operations lack sufficient scale and competitiveness in a number of sites. Due to weak industry fundamentals, intense competitive pressures and high feedstock costs, our petrochemicals operations incurred operating losses in both 2009 and 2008 of euro 675 million and euro 845 million, respectively. Results were also affected by the recognition of impairment losses amounting to euro 121 million and euro 278 million respectively as recoverable amounts of certain petrochemicals plants were lower than their carrying amounts due to deteriorating profitability prospects on the back of lowered expectations for industry fundamentals and unfavorable trends in the trading environment. Management does not expect any significant recovery in industry fundamentals and the trading environment for 2010, making it likely that further operating losses will be incurred.

Risks in the Company Gas & Power business segment

i) Market risks

In 2009 the Company s results of operations and cash flow were negatively affected by the severe contraction in gas demand due to the economic downturn and increasing competitive pressures resulting from large gas availability on the market place

In 2009 European gas demand was severely impacted by the economic downturn, as a fall in both producing activities and demand for electricity reduced gas consumption. European gas demand decreased by 7.4% from 2008, excluding seasonal effects. The Italian market was particularly hit by the downturn as demand fell by approximately 9 BCM from 2008, down 10%, and almost 10 BCM from the pre-crisis levels seen in 2007, down 12%, excluding seasonal effects. At the same time, new gas supplies entered the market as several operators, including Eni, completed plans to upgrade gas import pipelines from gas producing countries or projects to build new facilities to import gas to Europe via LNG carriers. In particular, Eni finalized plans to upgrade the import capacity of its two main pipelines from Russia and Algeria increasing capacity by an overall amount of 13 BCM/y (the gas pipelines TAG and TTPC), with new capacity entirely sold to third parties. A new LNG terminal with a capacity of 8 BCM/y commenced operations late in 2009, operated by a consortium of competitors. As a result, gas availability on the Italian market increased at a time when demand actually shrunk, resulting in oversupply. Accordingly, Eni s results of the gas marketing business, sales volumes and average gas selling margins[1] were driven down by rising competition and weak demand both in Italy and Europe. Large gas availability on other European markets also prevented the Company from disposing of part of its gas availability by selling it on European markets. This situation was exacerbated by lower gas consumption in the U.S. driven by the economic downturn and recent developments in extracting gas by unconventional sources. As a result of these trends, large amounts of LNG were re-directed towards Europe. The condition of oversupply on the European market is signaled by the circumstance that gas spot prices no longer appear correlated to trends in oil prices. This trend has resulted in Eni being less competitive as its supply costs are based on the price formulas of long-term supply agreements which link the price of gas to the price of oil.

The outlook for the European gas sector is challenging as current imbalances between demand and supply in Europe and Italy might negatively affect the Company s results of operation and cash flows in future years

The outlook for gas supply and demand both in Europe and Italy is challenging as GDP growth in the EU 27 Countries is expected to remain weak over the next few years and gas demand is expected to recover only gradually to pre-crisis levels. Currently, management does not expect that demand will recover to 2008 levels before 2013 and expects gas prices on spot markets to remain depressed for another one or two years. Gas availability will remain abundant on the marketplace as the Company expects that new infrastructures will be finalized over the next five to ten years, as publicly announced by certain consortia of competitors. In particular, it has been announced that a new pipeline will be built from Algeria to Italy via Sardinia with a 5 BCM capacity and a new LNG terminal will be started up in a yet to be identified location in Italy with 8 BCM capacity.

In addition, ongoing trends towards energy preservation and rising competition from renewable or alternative sources of energy will further dampen the recovery perspectives of gas demand. Specifically, at the March 2007 European Council, the European Heads of Government decided to adopt the Climate Action and Renewable Energy Package. This legislation was voted into law by the European Parliament in December 2008. The package, also known as "20-20-20 European Policy", 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 an improved energy efficiency within the EU Member States of 20% by 2020 and a 20% renewable energy target by 2020. To factor in those trends, management has revised downwards its long-term projections of both European and Italian gas demand growth. For further information see "Item 4 Gas & Power". The expected sluggish growth of demand, coupled with ample gas availability on the marketplace may adversely affect the Company s results of operations and cash flow in its gas marketing business in future years.

(1) For a definition of margin see "Glossary".

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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 to supplying the Italian gas market, the Company signed in the past a number of long-term gas supply contracts with key producing countries that supply the European gas markets. These contracts will ensure approximately 62.4 BCM of gas availability in 2010 (excluding the contribution of other subsidiaries and associates), have a residual life of approximately 20 years, and provide take-or-pay clauses whereby the Company is required to off-take minimum predetermined volumes of gas each year of the contractual term or, in case of failure, to pay the whole price, or a portion of it, 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 term of the contract execution. The amount of price that is required being paid in advance and the schedules for off-taking pre-paid gas vary from contract to contract. Generally speaking, cash pre-payments are calculated on the basis of the energy prices prevailing in the year of non-fulfillment with the balance due in the year when the gas is actually off-taken. Amounts of pre-payments range from 10 to 100 percent of the full price. 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, rights to off-take pre-paid gas in future years can only be exercised if the Company has fulfilled its minimum take obligation in a given year. In this case, Eni will pay the residual price for the gas that was not off-taken initially based on a purchase price calculated as average of market prices prevailing in the year when the gas is actually off-taken. Similar considerations apply to ship-or-pay contractual obligations.

Management believes that the current outlook for gas demand and large gas availability on the marketplace, as well as the possible evolution of sector-specific regulation, present significant risks to the Company s ability to fulfill its minimum take obligations associated with its long-term supply contracts.

In accordance with the terms of its long-term supply contracts, in 2009 Eni off-took lower volumes than the contractual minimum and recognized a trade payable amounting to euro 255 million corresponding to the amount of gas that the Company was required contractually to off-take.

Management believes that over the next two years the Company will experience failure to fulfill its take-or-pay obligations with respect to significant volumes of gas, unless demand fundamentals improve substantially and a better balance between demand and supply is achieved on the marketplace.

If Eni fails to off-take the contractual minimum amounts, it will be exposed to a price risk, because the purchase price Eni will ultimately be required to pay is based on prices prevailing after the date on which the off-take obligation arose. In addition, Eni is subject to the risk of not being able to dispose of pre-paid volumes. The Company also expects to incur financing costs to pay cash advances corresponding to contractual minimum amounts. As a result, the Company s selling margins, results of operations and cash flow may be negatively affected.

Eni is committed to increasing natural gas sales in Europe. If Eni fails to achieve this target, future growth prospects may be adversely affected. Furthermore, Eni may be unable to fulfill its minimum take obligations under its take-or-pay purchase contracts and this could adversely impact 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 it has entered into with major natural gas producing countries (namely Russia, Algeria, Libya, Norway and the Netherlands) and synergies from the acquisition of the Belgian gas operator Distrigas that was completed in 2009. 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

The opening of the Italian natural gas market as per Legislative Decree No. 164/2000 has gradually increased competition on the market thus reducing margins

Legislative Decree No. 164/2000 opened the Italian natural gas market to competition, impacting on Eni s activities, as the company is engaged in all the phases of the natural gas chain. The opening to competition was achieved through the enactment of certain antitrust thresholds on volumes input into the national transport network and on volumes sold to final customers. Specifically, these antitrust thresholds are effective until December 31, 2010 and prescribe that: (i) operators transmit a volume of imported or domestically produced gas into the national transport network which shall not be higher than a predetermined share of Italian final consumption. This share was 75% of total final consumption in the first year of regulation, decreasing by 2 percentage points per year to achieve a 61% threshold in terms of final consumption by 2009; and (ii) operators are forbidden from marketing gas volumes to final customers in excess of 50% of overall volumes marketed to final customers. Compliance with these ceilings is verified annually by comparing actual average shares reached by any operator in a given three-year period for both volumes input and volumes marketed to customers to average shares permitted by the law for the same period. Actual shares are computed net of losses (in the case of sales) and volumes of natural gas consumed in own operations. Based on a bill passed by the Italian upper house, Eni expects that these antitrust thresholds will be renewed when they expire in 2010.

These antitrust thresholds enabled new competitors to enter the Italian gas market, resulting in declining selling margins on gas. In addition, certain competitors of Eni are supplied by the Company itself, generally on the basis of long-term contracts. This is a result of the fact that, in order to comply with the above mentioned regulatory thresholds relating to volumes supplied through the national transport network and sales volumes in Italy, Eni sold part of its gas availability under its take-or-pay supply contracts to third parties importing said volumes to Italy and marketing them to Italian customers.

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 200,000 CM/y (qualified as non eligible customers as of December 31, 2002 as defined by Legislative Decree No. 164/2000) taking into account the public goal of containing the inflationary pressure due to rising energy costs. Accordingly, decisions of the Authority on these matters may limit the ability of Eni to pass an increase in the cost of fuels onto final consumers of natural gas. Following a complex and lengthy administrative procedure started in 2004 and finalized in March 2007 with Resolution No. 79/2007, the Authority finally established a new indexation mechanism for updating the raw material cost component in supplies to residential and commercial users consuming less than 200,000 CM/y, establishing, among other things that Italian natural gas importers including Eni must renegotiate wholesale supply contracts in order to take account of the new indexation mechanism of the raw material cost component. This indexation mechanism has been recently updated based on Resolution No. 64/2009 of the Authority, which provides that changes in a preset basket of hydrocarbons are transferred to the cost of the supply to those customers. Also a floor has been established in the form of a fixed amount that applies only at certain low level of international prices of hydrocarbons. The Company does not expect any material impact following enactment of Resolution No. 64/2009.

However, management cannot exclude the possibility that in the future the Authority could implement measures in this matter which may negatively affect Eni results of operations and liquidity. On March 26, 2010 the Authority for Electricity and Gas published a consultation document regarding certain proposed amendments to the current mechanism that is used to update the raw material cost component in supplies to residential users. The document addresses Italian gas importers, including Eni. The Authority reaffirmed its belief that such cost component should continue being linked to supply prices as provided by the long-term contracts held by Eni as the incumbent operator in the Italian gas market, as evidence suggests that there have not been sufficiently liquid spot markets in Italy. However, the Authority considers that Eni still holds as large market power as to influence wholesale gas prices. Based on that belief, the Authority suggests that the incumbent operator disposes of predetermined amounts of gas at preset economic conditions that take into account the supply costs of an efficient portfolio of long-term supply contracts which could be lower than current wholesale prices realized by Eni. Alternatively, those gas disposals might be in favor of an independent buyer for amounts that might possibly cover the entire capacity of the wholesale market in Italy. Those proposals require establishment of adequate rules by relevant administrative authorities. In case the rules are not implemented, the Authority plans to continue updating the raw material component in supplies to residential customers on the base of the current updating mechanism as it schedules to do in the fourth quarter of 2010. The eventual update will take into account of any effects associated with ongoing renegotiations of long-term supply contracts and may lead to lower wholesale gas prices.

Due to the regulated access to natural gas transport infrastructures in Italy, Eni may not be able to sell in Italy all the natural gas volumes it planned to import and, as a consequence, the Company may be unable to sell all the natural gas volumes which it is committed to purchase under take-or-pay contract obligations

Other risk factors deriving from the regulatory framework are associated with the regulation of the access to the Italian gas transport network that is currently set by Decision No. 137/2002 of the Authority for Electricity and Gas. The decision is fully incorporated into the network code presently in force as prepared by the system s operator. The decision sets priority criteria for transport capacity entitlements at points where the Italian transport network connects with international import pipelines (the so-called entry points to the Italian transport system). Specifically, operators that are holders of take-or-pay contracts, as in the case of Eni, are entitled to a priority in allocating available transport capacity within the limit of average daily contractual volumes. Gas volumes exceeding average daily contractual volumes are not entitled to any priority and, in case of congestion at any entry points, they are entitled available capacity on a proportionate basis together with all pending requests for capacity assignments. Under its take-or-pay purchase contracts, Eni has the right to off-take daily volumes larger than average daily contractual volumes. This flexibility is important to Eni s commercial programs as it is used when demand peaks, usually during the wintertime. In the event congestion occurs at entry points to the Italian transport network, based on current regulations, available transport capacity would be entitled firstly to operators having a priority right, i.e. holders of take-or-pay contracts within the limits of average daily contractual volumes. Then any residual available transport capacity would be allocated in proportion to all pending capacity requests. However, in planning its commercial flows, the Company normally assumes to make full use of its contractual flexibility and to obtain all necessary capacity entitlements at the entry points to the national transport network. Those assumptions may be inconsistent with rules sets by Decision No. 137/2002 specifically with regard to priority criteria governing capacity entitlements. Eni considers Decision No. 137/2002 to be illegitimate as it is, in Eni s view, in contrast with the rationale of the European regulatory framework on the gas market as provided in European Directive 03/55/CE. The Company based on that belief has commenced an administrative procedure to repeal Decision No. 137/2002 before an administrative court which recently confirmed in part Eni s position. An administrative appeals court also confirmed the Company s position. Specifically, the Court stated that the purchase of the contractual flexibility is an obligation on part of the importer, which responds to a collective interest. According to the Court, there is no reasonable motivation whereby volumes corresponding to such contractual flexibility should not be granted priority in access to the network, also in case congestion occurs. At the moment, however, no case of congestion occurred at entry points to the Italian transport infrastructure such to impairing Eni s marketing plans. Management cannot predict a final outcome of this proceeding. See "Item 4 Regulation of the Italian Hydrocarbons Industry Gas & Power".

Management also believes that Eni s results of operations and cash flows could be adversely affected should a combination of market conditions and regulatory constraints prevent Eni from selling its whole availability of natural gas purchased to fulfill its minimum take contract obligations. See "Item 5 Management Expectations of Operations".

A number of mandatory gas release measures have been recently implemented in Italy resulting in a negative impact on Eni s results of operations and liquidity. Management cannot exclude that similar measures will be implemented in future years

Gas release measures are administrative acts whereby Eni is obliged to dispose of certain amounts of gas at set prices and conditions as provided in the relevant gas release measure. Those measures are intended to increase flexibility and liquidity in the gas market. This measure strongly affected Eni s marketing activity in Italy. In 2004, based on certain agreements with the Antitrust Authority, Eni released in a four-year period a total amount of 9.2 BCM (2.3 BCM/y between October 1, 2004 and September 30, 2008) and the related transport capacity. In addition, in 2007 Eni agreed to adhere to a new gas release program involving 4 BCM which were disposed of in a two-year period (from October 1, 2007 and September 30, 2009). For thermal year 2009/2010 Italian Law No. 99/2009 introduced a new obligation for Eni to make additional sales for a total of 5 BCM of gas in yearly and half-yearly amounts. Although the allotment procedure (bid) was based on a minimum price set by the Ministry for Economic Development as proposed by the Authority for Electricity and Gas only a 1.1 BCM portion of the gas release was awarded out of the 5 BCM which had been planned. The price set by the Ministry is lower than the average price of Eni s sales in Italy.

For the next few years, based on indications made by the AEEG (in a report to the Parliament on the situation of the gas and electricity market in Italy as provided in Resolution PAS 3/2010), Eni cannot exclude the possibility that new gas release programs will be imposed on it. As a consequence, future results and cash flows could be negatively affected.

The Italian Government, Parliament and the regulatory authorities in Italy and in Europe may take further steps to increase competition in the Italian natural gas market and such regulatory developments may adversely affect Eni s results of operations and cash flows

Italian administrative and governmental institutions and political forces are urging a higher degree of competition in the Italian natural gas market and this may produce significant developments in this area. A brief description follows of certain recently enacted laws and certain proceedings before the Authority for Electricity and Gas and the Italian Antitrust Authority in order to allow investors to gain some insight into the complexity of this matter. For a full discussion of laws and procedures described herein see "Item 4 Regulation of the Italian Hydrocarbons Industry Gas & Power".

Italian Parliament is required to enact the third European Directive on the gas market No. 73 by March 2011. The Directive prescribes that member states choose one of two options for ensuring carriers independence in case transport systems belong to a vertically integrated company. One of these options provides that a parent company involved in both gas production and marketing and transport divests its interests in the carrier subsidiary. Eni currently owns a majority stake in the Italian carrier company Snam Rete Gas which owns and manages approximately 97% of the Italian natural gas transport infrastructure (Eni s share being 52.54%). Following an internal reorganization, Snam Rete Gas also manages all of Eni s activities in the distribution sector and in storage. See "Item 4 Gas & Power Reorganization of the regulated businesses in Italy". Eni is not able to predict developments on this matter.

Also in 2003, Law No. 290 was enacted in Italy which prohibits Eni from holding an interest higher than 20% in undertakings owning natural gas transport infrastructure in Italy (Eni currently holds a 52.54% interest in Snam Rete Gas). A decree is expected to be enacted by the Italian Prime Minister to establish the relevant provisions to implement this mandatory disposal. The deadline for the disposal, which was initially scheduled for December 31, 2008, is to be re-scheduled in a 24-month deadline following enactment of the decree from the Italian Prime Minister. Currently, Eni is unable to predict a deadline for this disposal.

In recent years, both the Italian Authority for Electricity and Gas and the Italian Antitrust Authority (the "Antitrust Authority") have conducted several reviews and inquiries on the Italian natural gas market, targeting the overall level of competition of the Italian natural gas market, the degree of opening to competition of the residential sector, levels of entry-exit barriers, and other areas such as sub-investment in the storage sector. Virtually the entire storage capacity belong to Eni through its indirect interest in Stoccaggi Gas Italia SpA, which is wolly owned by Snam Rete Gas SpA. In 2009, the Italian Antitrust commenced an inquiry targeting the possible existence of entry barriers in the residential sector and alleged anti-competitive practices on the part of sellers which are integrated in the activity of gas distribution, including Eni and the subsidiary Italgas (which is wolly owned by Snam Rete Gas SpA). See Note 28 to the Consolidated Financial Statements for a full description of such proceeding. Both the Authority for Electricity and Gas and the Antitrust Authority both believe that the vertical integration of Eni in the supply, transport, distribution, storage and marketing of gas may hamper the development of competition in Italy.

Management believes the institutional debate on the degree of competition in the Italian natural gas market and the regulatory activity to be areas of attention 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 (particularly the Authority s Decisions No. 248/2004, 134/2006 and 79/2007) see "Item 4 Regulation 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. In the years prior to 2008, Eni recorded significant loss provisions due to unfavorable developments in certain antitrust proceedings before the Italian Antitrust Authority, and the European Commission. It is possible that the Group may incur significant loss provisions in future years relative to ongoing antitrust proceedings or possible new proceedings. The Group is particularly exposed to this risk in its natural gas and refining and marketing activities due to the fact that Eni is the incumbent operator in those markets in Italy and a large European gas player. See Note 28 to the Consolidated Financial Statements for a full description of Eni s main pending antitrust proceedings. Our main antitrust matter relates to an ongoing proceeding before the European Commission with respect to alleged anti-competitive practices designed to harm competition in the European gas market in violation of Article No. 82 of the EU Treaty and Article No. 54 of the SEE. The proceeding involved Eni and other European players. Eni received a statement of objections from the European Commission which alleged that during the 2000-2005 period Eni was responsible for limiting the access of third parties to the gas pipelines TAG, TENP and Transitgas, thus restricting gas availability in Italy. On February 4, 2010, Eni formally submitted the European Commission a set of structural remedies relating certain international gas pipelines. With prior agreement from its partners, Eni committed to dispose of its interests in the German TENP, in the Swiss Transitgas and in the Austrian TAG gas pipelines. The European Commission intends to submit these remedies to a market test. In case the Commission approves those remedies upon conclusion of the market test, Eni will be in the position to settle the matter without imposition of any fine or other remedial measures.

Based on available information and its knowledge of the proceeding, the Company is currently unable to determine the outcome of the matter.

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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 may incur material operating expenses and expenditures in relation to compliance with applicable environmental, health and safety regulations

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, 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 water resulting from the operation of oil and natural gas extraction and processing plants, petrochemical plants, refineries, service stations, vessels, oil carriers, pipeline systems and other facilities owned by Eni. In addition, Eni s operations are subject to laws and regulations relating to the production, handling, transportation, storage, disposal and treatment of waste materials. Breach of environmental, health and safety laws exposes the Company s employees to criminal and civil liability and the Company to the incurrence of liabilities associated with compensation for environment health or safety damage. Additionally, in the case of violation of certain rules regarding safety in the workplace, the Company can be liable as provided for by a general EU rule on businesses liability due to negligent or willful conduct on part of their employees as adopted in Italy with 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 environmental, health and safety laws and regulations, also taking into account possible future developments in environmental regulations in Italy and in other countries where Eni operates, particularly current and proposed fuel and product specifications, emission controls and implementation of increasingly strict measures decided at both international and country level to reduce greenhouse gas emissions. For more discussion about this topic see "Item 4 Environmental regulations".

Eni s results of operations and financial condition are exposed to risks deriving from environmental, health and safety accidents and liabilities

Risks of environmental, health and safety incidences and liabilities are inherent in many of Eni s operations and products. Notwithstanding management's belief that Eni adopts high operational standards to ensure safety of its operations and to protect the environment and health of people and employees, it is possible that incidents like blow-outs, spill-overs, contaminations and similar events could occur that would result in damage to the environment, employees and communities. 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 for 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. Particularly, Eni is performing a number of remedial plans to restore and clean-up certain industrial sites that were contaminated by the Group s industrial activities in previous years, mainly in Italy. Remedial actions are expected to continue in the foreseeable future, impacting our liquidity as 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 amount represents the management s best estimates of future environmental expenses to be incurred. In 2009, the Company s environmental provision increased by euro 280 million.

Notwithstanding this, 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 chance of as yet unknown contamination; (ii) the results of on-going 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 site; (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 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 party to a number of civil actions and administrative proceedings arising in the ordinary course of business. In 2009, we increased our legal proceeding provision by euro 372 million due to the estimated probable losses associated with ongoing litigations. Of that amount, euro 250 million related to the possible resolution of the investigation related to the TSKJ consortium based on the current status of the ongoing discussions with U.S. Authorities. The matter is fully disclosed in the section "Legal Proceedings" in Note 28 to the Consolidated Financial Statements. This estimate in particular should be read in light of the qualifications set forth in the last sentence of this paragraph. 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.

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 Petrochemical segments are affected by changes in the price of crude oil and by 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 different 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 Petrochemical businesses, depends upon the speed at which the prices of gas and products adjust to reflect these changes. Wholesale margins in the Gas & Power business are substantially independent from fluctuations in crude oil prices as purchase and selling prices of natural gas are contractually indexed to prices of crude oil and certain refined products according to similar pricing schemes. However, quarterly performance and year-to-year comparability of results of Eni s natural gas business may be somewhat affected by the indexation mechanism of the raw material component in gas supplies to residential customers and certain resellers to residential customers in Italy in accordance with applicable regulations from the Italian Authority for Electricity and Gas. Specifically, this indexation mechanism provides a certain time lag between movements in the price of crude oil and the related adjustment to the selling price of natural gas. For a detailed discussion of this indexation mechanism in Italy see "Item 4 Regulation Gas & Power Natural gas prices".

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

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

Results of operations of the 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 as outlined above. The prices of refined products in turn 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 crude qualities vs. light crude qualities, taking into account the ability of Eni s refineries to process complex crudes that represents a cost advantage when market prices of heavy crudes are relatively cheaper than the marker Brent price. In 2009, Eni refining margins decreased substantially due to the rapid recovery in oil prices which the Company was unable to transfer on to final prices of refined products due to weak demand, high worldwide and regional inventory levels and excess refining capacity. Also, Eni s results of operation in its refining segment were affected by narrowing differential between heavy and light crude qualities resulting in poor margins on complex throughputs. Management does not expect any significant recovery in industry fundamentals in 2010. The sector as a whole will continue to suffer from weak demand and excess capacity, while the cost of oil feedstock is seen rising and price differentials to remain compressed. In this context, management expects that the Company refining margins will remain at below break-even levels.

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 changes in oil prices which influence changes in purchase costs of petroleum-based feedstock. 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 2009, the profitability of Eni s petrochemical segment was significantly affected by lower selling margins for commodity petrochemical products due to high purchase costs for oil-based feedstock that were not fully transferred to selling prices of products, as well as weak demand and competitive pressures. These negative factors also triggered asset impairments. Management s outlook for 2010 remains challenging, as industry fundamentals are not expected to improve substantially. Weak demand, competition, and high oil-based feedstock costs will continue to negatively affect Eni s results of operations and liquidity in this business segment.

Risks from Acquisitions

Eni constantly monitors the oil and gas market in search of opportunities to acquire individual assets or corporations in order to achieve its growth targets or complement its asset portfolio. Acquisitions entail an execution risk an important 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 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 may be adversely affected.

Credit risk

Credit risk is the potential exposure of the Group to losses in case counterparties fail to perform or pay amounts due. Credit risks arise from both commercial partners and financial ones. Although the Group has not experienced in the past material non-performance from its counterparties, due to the severity of the current economic and financial crisis it is possible that we may experience a higher than normal level of counterparty failure. In our consolidated financial statements for the year 2008, we accrued an allowance against doubtful accounts amounting to euro 251 million more than doubling the allowance made a year earlier. In 2009 Consolidated Financial Statements we made a further allowance for doubtful accounts amounting to euro 260 million, mainly relating to the Gas & Power business. Management believes that the Gas & Power business is particularly exposed to the ongoing impacts of the economic and financial crisis due to its large and diversified customer base which include a large number of middle and small businesses and retail customers.

Exchange Rates

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 Petrochemical 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 results of operations and liquidity because it reduces booked revenues by an amount greater than the decrease in dollar-denominated expenses. The Exploration & Production segment is particularly affected by movements in the U.S. dollar vs. the euro exchange rates. In 2008, Eni s operating profit in this business segment has been impacted by an estimated amount of euro 1.2 billion due to a 7.3% depreciation of the U.S. dollar versus the euro. This trend reversed in 2009 resulting in an addition to reported operating profit which was estimated in euro 500 million.

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.

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.

Interest Rates

Interest on Eni s finance 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 finance debt.

Critical Accounting Estimates

The preparation of financial statements requires management to make certain accounting estimates that are characterized by a high degree of uncertainty, complexity and judgment. These estimates affect the reported amount of the Company s assets and liabilities, as well as the reported amount of the Company s income and expenses for a given period. 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; the availability of new informative elements, variations in economic conditions such as prices, significant factors (e.g. removal technologies and costs) and the final outcome of legal, environmental or regulatory proceedings. See "Item 5 Critical Accounting Estimates".

Item 4. INFORMATION ON THE COMPANY

History and Development of the Company

Eni SpA with its consolidated subsidiaries is engaged in the oil and gas, power generation, petrochemicals, oilfield services and engineering industries. Eni has operations in 77 countries and 78,417 employees as of December 31, 2009.

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: www.eni.com.

The name of the agent of Eni in the United States is De Luca Vincenzo, 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 40 countries, including Italy, the UK, Norway, Libya, Egypt, Angola, Nigeria, Congo, the U.S., Kazakhstan, Russia and Australia. In 2009, Eni produced 1,716 KBOE/d on an available for-sale basis. As of December 31, 2009, Eni s total proved reserves of subsidiaries stood at 6,209 mmBOE; Eni s share of reserves of equity-accounted entities amounted to 362 mmBOE. In 2009, Eni s Exploration & Production segment reported net sales from operations (including inter-segment sales) of euro 23,801 million and operating profit of euro 9,120 million.

Eni s Gas & Power segment engages in supply, transport, distribution, storage, re-gasification and marketing of natural gas, electricity and LNG. This segment also includes the activity of power generation that is ancillary to the marketing of electricity. In 2009, Eni s worldwide sales of natural gas amounted to 103.72 BCM, including 6.17 BCM of gas sales made directly by the Eni s Exploration & Production segment in Europe and the U.S. Sales in Italy amounted to 40.04 BCM, while sales in European markets were 55.45 BCM that included 10.48 BCM of gas sold to certain importers to Italy. In 2009, following the reorganization of the regulated businesses the parent company Eni SpA concluded the sale of the entire share capital of its fully-owned subsidiaries Italgas SpA and Stoccaggi Gas Italia SpA to its 52.54 per cent-owned subsidiary Snam Rete Gas.

Through Snam Rete Gas, Eni operates an Italian network of high and medium pressure pipelines for natural gas transport that is approximately 31,531-kilometer long, while outside Italy Eni holds capacity entitlements on a network of European pipelines extending for approximately 4,400 kilometers made up of high pressure pipelines to import gas from Russia, Algeria, Libya and North Europe production basins to European markets. Snam Rete Gas, through its 100 percent-owned subsidiary Italgas and other subsidiaries, is engaged in natural gas distribution activity in Italy serving 1,322 municipalities through a low pressure network consisting of approximately 49,973 kilometers of pipelines as of December 31, 2009. Snam Rete Gas, through its wholly-owned subsidiary Stoccaggi Gas Italia operates in natural gas storage activities in Italy through eight storage fields. Eni produces power and steam at its operated sites of Livorno, Taranto, Mantova, Ravenna, Brindisi, Ferrera Erbognone and Ferrara with a total installed capacity of 5.3 GW as of December 31, 2009. In 2009, sales of power totaled 33.96 TWh. Eni operates a re-gasification terminal in Italy and holds indirect interest or capacity entitlements in a number of LNG facilities in Europe, Egypt and in certain projects under construction in the U.S. In 2009, Eni s Gas & Power segment reported net sales from operations (including inter-segment sales) of euro 30,447 million and operating profit of euro 3,687 million.

Eni s Refining & Marketing segment engages in refining and marketing of petroleum products mainly in Italy and in the rest of Europe. In 2009, processed volumes of crude oil and other feedstock amounted to 34.55 mmtonnes and sales of refined products were 45.59 mmtonnes, of which 26.68 mmtonnes in Italy. Retail sales of refined product at operated service stations amounted to 12.02 mmtonnes including Italy and the rest of Europe. In 2009, Eni s retail market share in Italy through its Agip-branded network of service stations was 31.5%. In 2009, Eni s Refining &

Marketing segment reported net sales from operations (including inter-segment sales) of euro 31,769 million and operating net loss of euro 102 million.

Eni s petrochemical activities include production of olefins and aromatics, basic intermediate products, polyethylene, polystyrenes, and elastomers. Eni s petrochemical operations are concentrated in Italy and Western Europe. In 2009, Eni sold 4.3 mmtonnes of petrochemical products. In 2009, Eni s Petrochemical segment reported net sales from operations (including inter-segment sales) of euro 4,203 million and an operating net loss of euro 675 million.

Eni s oilfield services, construction and engineering activities are conducted through its 42.91 per cent-owned subsidiary Saipem and Saipem s controlled entities. Activities involve offshore construction, particularly fixed platform installation, sub-sea pipe laying and floating production systems and onshore construction. Offshore and onshore drilling services and engineering and project management services are also provided to the oil and gas, refining and petrochemical industries. In 2009, Eni s Engineering & Construction segment reported net sales from operations (including intra-group sales) of euro 9,664 million and operating profit of euro 881 million.

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

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Strategy

Eni s strategy is to grow the Company s main businesses over both the medium and the long-term, with improving profitability. This strategy has remained unchanged in spite of the 2009 economic downturn and uncertain perspectives for global energy demand. Specifically, the Company is planning for:

- growing profitably oil and gas production in the Exploration & Production business;
- preserving profitability in the Gas & Power business by leveraging on the Company s competitive position on the European market in spite of an uncertain demand outlook and increasing competition;
- improving profitability and cash generation in the Refining & Marketing business by implementing cost reduction initiatives and tightly selecting our capital projects in the face of a difficult trading environment, also boosting profitability of marketing operations;
- improving revenues and profitability in our Engineering & Construction business leveraging on our strong order backlog and technologically-advanced assets; and
- managing efficiently and effectively our petrochemicals business.

In executing this strategy, management intends to pursue integration opportunities among businesses and within them and to strongly focus on efficiency improvement through technology upgrading, cost efficiencies, commercial and supply optimization and continuing process streamlining across all businesses. Over the next four-years, Eni plans to execute a capital expenditure program amounting to euro 52.8 billion to support continuing organic growth in its businesses. In 2010, Eni plans to invest approximately euro 14 billion, an amount roughly in line with 2009. Eni plans to fund those capital expenditure plans mainly by means of cash flows provided by operating activities. Capital projects will be assessed and implemented in accordance with tight financial criteria. Those will be the levers whereby the Company intends to preserve a solid capital structure targeting an optimal mix between net borrowings and shareholders equity. The Company intends to remunerate its shareholders through a progressive dividend policy. In 2010 management plans to distribute a dividend in line with 2009. In subsequent years, dividends are planned to be increased in line with OECD inflation. This dividend policy is based on the Company s planning assumptions of Brent oil prices at $65 per barrel flat in the next four years and other assumptions (see Item 5 Management s Expectations of Operations and Item 3 Risk Factors).

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 Management of Expectations of Operations".

In technological research and innovation activities, Eni plans to implement significant capital expenditures amounting to euro 1.4 billion to develop such technologies that management believes may ensure competitive advantages in the long-term. Eni plans to continue developing ongoing programs focused on reducing costs to find and recover hydrocarbons, developing clean fuels, upgrading heavy crude (in particular the EST project), monetizing natural gas through projects such as high pressure high distance gas transmission (TAP) and Gas to Liquids (GTL), and protecting the environment by investing in the fields of renewable sources of energy and reduction of GHG emissions.

Significant Business and Portfolio Developments

The significant business and portfolio developments that occurred in 2009 and to date in 2010 were the following:

- In January 2010, Eni leading a consortium of international companies and the Iraqi National Oil Companies, South Oil Co and Missan Oil Co signed a technical service contract, under a 20-year term with an option for further 5 years, to develop the Zubair oil field (Eni 32.8%). The field was awarded in October 2009 to the Eni-led consortium following a successful first bid round and was offered under a competitive bid starting on June 30, 2009. The partners of the project plan to gradually increase production to a target plateau level of 1.2 mmBOE/d by 2016. The contract provides that the consortium will earn a remuneration fee on the incremental oil production once production has been raised by 10 percent from its current level of approximately 180,000 BBL of oil per day and will recover its expenditures through a cost recovery mechanism based on the revenues from the field production.

In January 2010, Eni and the Venezuelan National Oil Company PDVSA signed an agreement for the joint development of the giant field Junin 5 with 35 BBBL of certified heavy oil in place, located in the Orinoco oil belt. Production start-up is planned for 2013 at an initial level of 75 KBBL/d and a long term production plateau of 240 KBOE/d is targeted. Development will be conducted through an "Empresa Mixta" (Eni 40%, PDVSA 60%). At the time of the establishment of the Empresa Mixta Eni will disburse a bonus of $300 million, and further $346 million will be paid upon the achievement of certain project milestones. The agreement also includes an option to deploy Eni s proprietary technology in hydrogenation for the conversion of heavy oils. Finally, Eni will present a project for the construction of a power plant in the Guiria peninsula.

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In April 2009, Gazprom exercised its call option to purchase a 20% interest in OAO Gazprom Neft held by Eni based on the existing agreements between the two partners. The exercise price of the call option collected by Eni on April 24, 2009 amounting to euro 3,070 million is equal to the price ($3.7 billion) outlined in the bid procedure held on April 4, 2007 for the assets of bankrupt Russian company Yukos as adjusted by subtracting dividends distributed and adding the contractual yearly remuneration of 9.4% on the capital employed and financing collateral expenses. A gain amounting to euro 172 million was recognized in the profit of the period as remuneration of the capital invested and recovery of collateral expenses.

In September 2009, Eni and its Italian partner Enel in the 60-40% owned joint-venture OOO SeverEnergia completed the divestment of a 51% stake in the venture to Gazprom based on the call option exercised by the Russian company. Eni collected euro 155 million (or $230 million at the EUR/USD exchange rate of 1.48 as of the transaction date) corresponding to approximately 25% of the whole amount of the transaction ($940 million net to Eni). The remaining 75%, amounting to euro 526 million (or approximately $710 million at the EUR/USD exchange rate of 1.35 as of the transaction date) was collected on March 31, 2010. A gain amounting to euro 100 million was recognized in the profit for the year 2009. The gain was associated with interest income at an annual rate of 9.4% accruing on the initial investment in the venture when it was acquired on April 4, 2007 based on the contractual arrangements between Eni and Gazprom. The three partners are committed to producing first gas from the Samburskoye field by June 2011, targeting a production plateau of 150 KBOE/d within two years from the start of production.

In addition, in 2009 Eni closed the following transactions:

In February 2009, Eni signed the project for the feasibility study addressing the utilization of associated gas feeding a new onshore power plant and upstream sector initiatives in the Angola onshore basins, as well as other projects in sustainability. Similar agreements were made in Egypt, the Democratic Republic of Congo and Pakistan.

On May 12, 2009 Eni and the Ministry for Oil of Egypt agreed on a ten-year extension of the concession for the giant Belayim field. Eni will invest approximately $1.5 billion over the next five years to execute development expenditures, upgrading actions and operating costs.

On May 15, 2009 Eni and Gazprom have agreed upon a new scope of work in the development project of the South Stream pipeline, aimed at increasing its transport capacity from an originally planned amount of 31 BCM/y to 63 BCM. Eni and Gazprom confirmed their full commitment to developing the project which, if the ongoing feasibility study produces a positive outcome, will build a new route to supply Russian gas to Europe.

In June 2009, Eni finalized the acquisition from Quicksilver Resources Inc of a 27.5% interest in the Alliance area, in Northern Texas, covering approximately 53 square kilometers, with gas shale reserves. Quicksilver will retain the 72.5% of the interests and operatorship of the properties. The cash consideration for the transaction amounted to $280 million. The expected production from the acquired assets will amount to 4,000 BOE/d net to Eni for the full year 2009, ramping up to approximately 10,000 BOE/d by 2011.

In October 2009, Eni and its commercial partners in Turkey and Russia, working on the construction of the Samsun-Ceyhan pipeline, signed a Memorandum of Understanding committing to discuss the definition of the economic and contractual conditions for Russian companies to participate in the Samsun-Ceyhan Project in order to ensure the volume of crude that would guarantee the economic sustainability of the project. On the same occasion, representatives of the governments of Italy, Turkey and Russia reaffirmed their support to the project which will build a by-pass to facilitate safer transport across the Bosphorus and Dardanelles Straits as well as reduce the impact on the region s complex and delicate ecosystem.

In November 2009, Eni was awarded a 37.8% stake in the Indonesian Sanga Sanga license for the production of coal bed methane. Recent preliminary studies in the block showed a resource potential of about 3,920 BCF of gas to be verified through an appraisal program that will commence in 2010.

In November 2009, Eni and the Kazakh National Oil Company KazMunayGas signed a co-operation agreement for initiatives in the fields of developing, exploring and producing hydrocarbon resources and industrial facilities in the Country. Under the agreement, Eni and KazMunayGas will jointly execute exploration studies, studies for the optimization of gas usage in Kazakhstan and the evaluation of a number of industrial initiatives including the upgrading of the Pavlodar refinery, in which KMG holds a majority interest.

In December 2009, Eni signed a memorandum of understanding with Turkmenistan aimed at promoting and reinforcing the partnership in the development of the oil industry of the Country. Eni will co-operate with the State companies and Agency for Hydrocarbons to carry out studies to ascertain the oil and gas potential of the country. Eni will contribute its expertise in technology and the sustainability field.

In January 2010, Eni signed an agreement for the acquisition of a number of marketing activities of refined products in Austria, including a retail network of 135 service stations, wholesale activities as well as commercial assets in aviation business and complementary logistic and storage activities. The finalization of the transaction is subject to the approval of the relevant antitrust authorities.

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In 2009, capital expenditures amounted to euro 13,695 million, of which 86% related to the Exploration & Production, Gas & Power and Refining & Marketing businesses, and primarily related to: (i) the development of oil and gas reserves (euro 7,478 million) deployed mainly in Kazakhstan, the United States, Egypt, Congo, Italy and Angola, and exploration projects (euro 1,228 million) carried out mainly in the United States, Libya, Egypt, Norway and Angola; (ii) the acquisition of proved and unproved properties amounting to euro 697 million mainly related to the acquisition of a 27.5% interest in assets with gas shale reserves from Quicksilver Resources Inc and extension of the duration of oil and gas properties in Egypt following the agreement signed in May 2009; (iii) the development and upgrading of Eni s natural gas transport and distribution networks in Italy (euro 919 million and euro 278 million, respectively) as well as the development and increase of the storage capacity (euro 282 million); (iv) 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 608 million); and (v) the upgrading of the fleet used in the Engineering & Construction segment (euro 1,630 million).

In 2009, Eni s acquisitions amounted to euro 2.32 billion and mainly related to the completion of the acquisition of Distrigas NV. Following the acquisition of the 57.243% majority stake in the Belgian company Distrigas NV from French company Suez-Gaz de France, Eni made an unconditional mandatory public takeover bid on the minorities of Distrigas (42.76% stake). On March 19, 2009, the mandatory tender offer on the minorities of Distrigas was finalized. Shareholders representing 41.61% of the share capital of Distrigas, including the second largest shareholder, Publigaz SCRL with a 31.25% interest, tendered their shares. The squeeze-out of the residual 1.14% of the share capital was finalized on May 4, 2009. After this, Distrigas shares have been delisted from Euronext Brussels. The total cash consideration amounted to approximately euro 2.05 billion.

In 2008, capital expenditures amounted to euro 14,562 million, of which 84% related to the Exploration & Production, Gas & Power and Refining & Marketing divisions and concerned mainly: (i) the development of oil and gas reserves (euro 6,429 million) deployed mainly in Kazakhstan, Egypt, Angola, Congo and Italy and exploration projects (euro 1,918 million), primarily in the United States, Egypt, Nigeria, Angola and Libya; (ii) the purchase of proved and unproved property for euro 836 million related mainly to the extension of mineral rights in Libya following an agreement signed in October 2007 with the state company NOC and the purchase of a 34.81% interest in the ABO project in Nigeria; (iii) the development and upgrading of Eni s natural gas transport and distribution networks in Italy (euro 1,130 million and euro 233 million, respectively) and upgrading of natural gas import pipelines to Italy (euro 233 million); (iv) the ongoing construction of combined cycle power plants (euro 107 million); (v) projects designed to upgrade the conversion capacity and flexibility of Eni s refineries, including construction of a new hydrocracking unit at the Sannazzaro refinery, and to build of new service stations and upgrade of existing ones in Italy and outside Italy (totaling euro 965 million); and (vi) the upgrading of the fleet used in the Engineering & Construction division (euro 2,027 million).

In 2008, Eni s acquisitions amounted to euro 5.85 billion (euro 4.3 billion net of acquired cash of euro 1.54 billion) and mainly related to: (i) the acquisition of the 57.243% majority stake in Distrigas NV; (ii) the completion of the acquisition of Burren Energy Plc; (iii) the purchases of certain upstream properties and gas storage assets, related to the entire share capital of the Canadian company First Calgary operating in Algeria, a 52% stake in the Hewett Unit in the North Sea, a 20% stake in the Indian company Hindustan Oil Exploration Co; and (iv) other investments in non-consolidated entities mainly related to funding requirements for an LNG project in Angola.

In 2007, capital expenditures amounted to euro 10,593 million, of which 84.7% related to the Exploration & Production, Gas & Power and Refining & Marketing businesses, and primarily related to: (i) the development of oil and gas reserves (euro 4,788 million) deployed predominantly in Kazakhstan, Egypt, Angola, Italy and Congo, and exploration projects (euro 1,659 million) particularly in the Gulf of Mexico, Egypt, Norway, Nigeria and Brazil; (ii) development and upgrading of Eni s natural gas transport and distribution networks in Italy (euro 886 million) as well as upgrading of natural gas import pipelines to Italy (euro 253 million); (iii) the ongoing construction of combined cycle power plants (euro 175 million); (iv) projects designed to upgrade the conversion capacity and flexibility of Eni s refineries, including construction of a new hydrocracking unit at the Sannazzaro refinery, and to build and upgrade service stations (totaling euro 979 million); and (v) the upgrading of the fleet used in the Engineering & Construction segment (euro 1,410 million).

In 2007, Eni s acquisitions amounted to euro 9.7 billion and mainly related to: (i) a 60% interest in three Russian gas companies as part of the liquidation procedure of bankrupt Russian company Yukos. Through the same transaction Eni also purchased a 20% stake in the oil and gas company OAO Gazprom Neft. Gazprom was granted a call option to purchase a 51% interest in those three gas companies and the 20% stake in OAO Gazprom Neft; (ii) the purchase of upstream assets in the Gulf of Mexico; (iii) the purchase of upstream assets onshore Congo; (iv) the purchase of a 24.9% interest in Burren Energy; (v) the acquisition of a further 16.11% stake in the Ceska Rafinerska in the Czech Republic increasing Eni s ownership interest to 32.4%; (vi) the purchase of 102 retail fuel stations and related marketing assets located in the Czech Republic, Slovakia and Hungary; and (vii) the purchase of a 13.6% stake in the Angola LNG consortium.

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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 40 countries, including Italy, Libya, Egypt, Norway, the UK, Angola, Congo, the U.S., Kazakhstan, Russia, Algeria, Australia, Venezuela and Iraq. In 2009, Eni produced 1,716 KBOE/d on an available for-sale basis. As of December 31, 2009, Eni s total proved reserves amounted to 6,571 mmBOE; proved reserves of subsidiaries stood at 6,209 mmBOE; Eni s share of reserves of equity-accounted entities amounted to 362 mmBOE.

Eni s strategy in its Exploration & Production operations is to pursue profitable production growth leveraging on the Company s portfolio of assets and pipeline of development projects. We plan to achieve a production growth rate higher than 2.5% on average over the 2010-2013 periods, targeting a production level in excess of 2 mmBOE/d based on our long-term Brent price assumptions of 65 $/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 that target via organic developments, leveraging on the Company s asset portfolio. We plan to achieve 75% of that production level by continuing production ramp-up at our existing fields and 25% by successfully starting to production 41 new fields that based on management estimates are forecast to add up to 560 KBOE/d to the Company s production level by 2013. We have already sanctioned half of new projects and expect to sanction a further 40% in 2010. Management plans to maximize product contribution from existing fields, particularly those with long-life cycles, by applying its advanced recovery technologies, reservoir management capabilities and implementing actions to offset natural field depletion.

Eni intends to pay special attention to reserve replacement in order to ensure the medium-to long-term sustainability of the business. Eni intends to optimize its portfolio of development properties by focusing on areas where its presence is established, and divesting non-strategic or marginal assets. Eni also intends to develop certain LNG project in order to monetize its large base of gas reserves mainly in West Africa. We also plan to exercise tight cost control by achieving cost efficiencies associated with scale of operations and leveraging on our well-established presence in areas such as Africa where we believe development and production costs are lower than in other areas and increasing exposure to operated-projects.

In exploration activities, Eni intends to concentrate expenditures in well established areas of presence where availability of production facilities and existing know-how and competencies will enable the Company to readily put in production discovered reserves, reducing time-to-market and achieving cost efficiencies. Approximately 45% of planned exploration expenditures will be directed to such core areas (located mainly in the United States, Libya, Angola, Nigeria, Norway, Egypt, Congo and Indonesia). Eni also plans to selectively pursue high risk/high reward opportunities in areas with high mineral potential and to appraise the resource potential in recently entered areas like Gabon and Ghana. Eni expects to purchase new exploration permits and to divest or exit marginal or non strategic areas.

Management plans to invest approximately euro 37 billion to explore for and develop new reserves over the next four years; approximately euro 0.5 billion of which will be spent to build transportation infrastructures and execute LNG projects through equity-accounted entities. For the year 2010, management plans to spend euro 10.5 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.

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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. In prior periods, year-end liquids and natural gas prices were used in the estimate of proved reserves in accordance with then applicable rules.

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 judgment. Consequently, the estimated proved reserves of oil and natural gas may be subject to future revision and upward and downward revisions may be made to the initial booking of reserves due to analysis of new information. Proved reserves to which Eni is entitled under concession contracts are determined by applying Eni s share of production to total proved reserves of the contractual area, in respect of the duration of the relevant mineral right. Proved reserves to which Eni is entitled under Production Sharing Agreements are calculated so that the sale of production entitlements should cover expenses incurred by the Group to develop a field (cost oil) and on the profit oil set contractually (profit oil). A similar scheme applies to buy-back and service contracts.

Reserves Governance

Eni has always exercised centralized rigorous control over the process of booking proved reserves.

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 affirmed their compliance with the SEC rules[2]; D&M has also stated that the company formal guidelines, whenever SEC rules do not provide specific prescription, provide a reasonable interpretation in line with the generally accepted practices in the industry. When participating in exploration and production activities operated by others entities, Eni also estimates its proved reserves on the basis of the above guidelines.

The process for evaluating reserves, as described in the internal procedure, involves: (i) business unit manager (geographic units) and Local Reserves Evaluators (LRE), who perform the evaluation and classification of reserves including estimates of production profiles, capital expenditures, operating costs and costs related to asset retirement obligations; (ii) geographic area managers at head offices checking evaluation carried out by business unit managers; (iii) the Planning and Control Department which provides the economic evaluation of reserves; and (iv) the Reserve Department which, through Division Reserves Evaluators (DRE), provides independent reviews of the fairness and correctness of classifications carried out by the above mentioned units and aggregates worldwide reserve data.

The head of the Reserve Department attended the "Politecnico di Torino" and received a Master of Science degree in Mining Engineering in 1985. She has more than 20 years of experience in the oil and gas industry and more than 10 years of experience specifically in evaluating reserves.

Staff involved in the reserves evaluation process fulfill the professional qualifications requested and maintain the highest level of independence, objectivity and confidentiality in accordance with professional roles of conduct. Eni s

Reserves Evaluators qualifications comply with international standards established by the Society of Petroleum Engineers.

Reserves independent evaluation

Since 1991, Eni has requested qualified independent oil engineering companies to carry out an independent audit[3] of its proved reserves on a rolling basis. The description of qualifications of the person primarily responsible for the reserve audit is included in the third party audit report[4]. In the preparation of their reports, those independent evaluators rely, without independent verification, upon information furnished by Eni 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. This data, equally used by

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(2) See "Item 19 Exhibits".

(3) From 1991 to 2002, DeGolyer and MacNaughton; from 2003, also Ryder Scott Co.

(4) See "Item 19 Exhibits".

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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, reservoir performance, long-term development plans, future capital and operating costs.

In order to calculate the economic value of Eni equity reserves, actual prices applicable to hydrocarbon sales, price adjustments required by applicable contractual arrangements and other pertinent information are provided. In 2009, Ryder Scott Co and DeGolyer and MacNaughton provided an independent evaluation of almost 28% of Eni s total proved reserves as of December 31, 2009[5], confirming, as in previous years, the reasonableness of Eni s internal evaluations[6].

In the 2007-2009 three-year period, 86% of Eni total proved reserves were subject to independent evaluation. As of December 31, 2009 among the most important Eni properties, the only property which was not subject to an independent review was Barbara (Italy).

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, 2009, 2008 and 2007. Reserves data for 2009 is based on 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. Data for 2008 and 2007 are based on the last day price of the Company s fiscal year in accordance with then applicable rules.

HYDROCARBONS

(mmBOE)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total consolidated subsidiaries	Equity-accounted entities	Total
Year ended Dec. 31, 2007	**747**	**638**	**1,879**	**1,095**	**1,061**	**198**	**259**	**133**	**6,010**	**668**	**6,678**
Developed	534	537	1,183	766	494	127	158	63	3,862	101	3,963
Undeveloped	213	101	696	329	567	71	101	70	2,148	567	2,715
Year ended Dec. 31, 2008	**681**	**525**	**1,922**	**1,146**	**1,336**	**265**	**235**	**132**	**6,242**	**666**	**6,908**
Developed	465	417	1,229	827	647	168	133	62	3,948	107	4,055
Undeveloped	216	108	693	319	689	97	102	70	2,294	559	2,853
Year ended Dec. 31, 2009	**703**	**590**	**1,922**	**1,141**	**1,221**	**236**	**263**	**133**	**6,209**	**362**	**6,571**
Developed	490	432	1,266	799	614	139	168	122	4,030	74	4,104
Undeveloped	213	158	656	342	607	97	95	11	2,179	288	2,467

LIQUIDS

(mmBBL)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and	Total consolidated	Equity-accounted entities	Total

							Oceania	subsidiaries			
Year ended Dec. 31, 2007	**215**	**345**	**878**	**725**	**753**	**44**	**138**	**29**	**3,127**	**142**	**3,269**
Developed	133	299	649	511	219	35	81	26	1,953	26	1,979
Undeveloped	82	46	229	214	534	9	57	3	1,174	116	1,290
Year ended Dec. 31, 2008	**186**	**277**	**823**	**783**	**911**	**106**	**131**	**26**	**3,243**	**142**	**3,385**
Developed	111	222	613	576	298	92	74	23	2,009	33	2,042
Undeveloped	75	55	210	207	613	14	57	3	1,234	109	1,343
Year ended Dec. 31, 2009	**233**	**351**	**895**	**770**	**849**	**94**	**153**	**32**	**3,377**	**86**	**3,463**
Developed	141	218	659	544	291	45	80	23	2,001	34	2,035
Undeveloped	92	133	236	226	558	49	73	9	1,376	52	1,428

(5) Includes Eni s share of proved reserves of equity-accounted entities.

(6) From 1991 to 2002, DeGolyer and MacNaughton; from 2003, also Ryder Scott.

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NATURAL GAS

(BCF)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total consolidated subsidiaries	Equity-accounted entities	Total
Year ended Dec. 31, 2007	**3,057**	**1,675**	**5,751**	**2,122**	**1,770**	**880**	**696**	**598**	**16,549**	**3,022**	**19,571**
Developed	2,304	1,364	3,065	1,469	1,580	530	442	213	10,967	428	11,395
Undeveloped	753	311	2,686	653	190	350	254	385	5,582	2,594	8,176
Year ended Dec. 31, 2008	**2,844**	**1,421**	**6,311**	**2,084**	**2,437**	**911**	**600**	**606**	**17,214**	**3,015**	**20,229**
Developed	2,031	1,122	3,537	1,443	2,005	439	340	221	11,138	420	11,558
Undeveloped	813	299	2,774	641	432	472	260	385	6,076	2,595	8,671
Year ended Dec. 31, 2009	**2,704**	**1,380**	**5,894**	**2,127**	**2,139**	**814**	**629**	**575**	**16,262**	**1,588**	**17,850**
Developed	2,001	1,231	3,486	1,463	1,859	539	506	565	11,650	234	11,884
Undeveloped	703	149	2,408	664	280	275	123	10	4,612	1,354	5,966

Volumes of oil and natural gas applicable to long-term supply agreements with foreign governments in mineral assets where Eni is operator totaled 674 mmBOE as of December 31, 2009 (679 and 676 mmBOE as of December 31, 2008 and 2007, respectively). Said volumes are not included in reserves volumes shown in the table herein.

Activity of the year

	Subsidiaries			Equity-accounted entities		
	2007	2008	2009	2007	2008	2009
	(mmBOE)					
Additions to proved reserves	237	882	605	639	6	(296)
of which purchases and sales of reserves-in-place	*156*	*32*	*25*	*617*		*(314)*
Production for the year	(627)	(650)	(638)	(7)	(8)	(8)

	Subsidiaries		
	2007	2008	2009
	(%)		
Proved reserves replacement ratio of subsidiaries	38	136	95

Eni s proved reserves of subsidiaries as of December 31, 2009 totaled 6,209 mmBOE (oil and condensates 3,377 mmBBL; natural gas 16,262 BCF) representing a decrease of 33 mmBOE, or 5.3%, from December 31, 2008.

Additions to proved reserves booked in 2009 were 605 mmBOE and derived from: (i) revisions of previous estimates (261 mmBOE) mainly reported in Egypt, Italy, Congo, the United Kingdom and the United States which were partly offset by the unfavorable effect of higher oil prices on reserve entitlements in certain PSAs and buy-back contracts (down 100 mmBOE) resulting from higher oil prices from a year ago (the Brent price used in the reserve estimation process was 59.9 $/BBL in 2009 compared to 36.5 $/BBL in 2008). Higher oil prices also resulted in upward revisions associated with improved economics of marginal productions; (ii) extensions and discoveries (282 mmBOE), with main increases reported in Norway, Algeria, Iraq and Libya; (iii) improved recovery (37 mmBOE) mainly reported in Angola, Norway and Libya; and (iv) purchases and sales of mineral in place (25 mmBOE).

The largest additions were related to following fields/projects: Goliat in Norway, CAFC and MLE in Algeria, Belayim in Egypt due to the new extension terms that were agreed upon with relevant Egyptian authorities, M Boundi in Congo and Bahr Essalam in Libya as a result of continuing development activities and revisions as well as Zubair in Iraq due to the signing of the technical service contract.

Acquisitions for 26 mmBOE related mainly to a 27.5% stake purchased from Quicksilver Resources Inc in the Alliance area, in Texas.

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As of December 31, 2009 Eni s share of proved reserves of equity-accounted entities amounted to 362 mmBOE, a decrease of 304 mmBOE compared to December 31, 2008, mainly due to the divestment of a 51% stake in the joint venture OOO SeverEnergia (Eni s interest was 60%, currently 29.4%) after the call option exercised by Gazprom.

The new SEC rules allow the use of reliable technology (i.e. seismic, wireline formation test, logs and core) to justify the reserves estimate if it produces consistent and repeatable results. We did not have any material additions of proved reserves due to application of new reliable technologies.

Proved developed reserves of subsidiaries as of December 31, 2009 amounted to 4,030 mmBOE (2,001 mmBBL of liquids and 11,650 BCF of natural gas) representing 65% of total estimated proved reserves (63% and 64% as of December 31, 2008 and 2007, respectively).

The reserve replacement ratio for Eni s subsidiaries was 95% in 2009 (136% in 2008 and 38% in 2007). The reserve 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 the Consolidated Financial Statements). The reserve replacement ratio is a measure used by management to assess the extent to which produced reserves in the year are replaced by reserve additions booked. Management considers the reserve replacement ratio to be an important indicator of the Company to sustain its growth prospects. 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 infrastructure, as well as changes in oil and gas prices, political risks and geological and other environmental risks. Specifically, in recent years Eni s reserves replacement ratio has been affected by the impact of higher year-end oil prices on reserves entitlements in the Company s Production Sharing Agreements (PSAs) 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 prices for Brent crude oil 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. In 2009 this trend resulted in a lower amount of booked reserves associated with the Company s PSAs as the oil price was averaged higher than the previous year. See "Item 3 Risks associated with exploration and production of oil and natural gas" and "Uncertainties in estimates of oil and natural gas reserves".

The average reserve life index of Eni s proved reserves was 10.2 years as of December 31, 2009 which included reserves of both subsidiaries and equity-accounted entities.

Proved undeveloped reserves

Proved undeveloped reserves as of December 31, 2009 totaled 2,467 mmBOE. At year-end, liquids proved undeveloped reserves amounted to 1,428 mmBBL, mainly concentrated in Africa and Kazakhstan. Natural gas proved undeveloped reserves accounted for 5,966 BCF, mainly located in Africa and Russia.

In 2009, total proved undeveloped reserves decreased by 386 mmBOE. The main reasons for the variation are: (i) reclassification to proved developed reserves; (ii) divestment of a 51% stake in the joint-venture OOO SeverEnergia (Eni s interest being 60%) after the call option exercised by Gazprom; and (iii) addition from new projects and revisions.

During 2009, Eni converted approximately 370 mmBOE of proved undeveloped reserves to proved developed reserves. The main reclassification to proved developed were related to development activities and the start-up of the following fields: Blacktip (Australia), PY1 (India), Lennox (UK), Karachaganak (Kazakhstan), Longhorn (USA), Val d Agri (Italia), and Poinsettia (Trinidad & Tobago).

Main additions of proved undeveloped reserves were recorded in Rest of Europe, North Africa and Rest of Asia.

In 2009, capital expenditure amounted to approximately euro 2.2 billion and were made to progress the development of proved undeveloped reserves.

Reserves that remain proved undeveloped for five or more years are a result of several physical 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 infrastructure or plant capacities and contractual limitations that establish production levels.

The Company estimates that approximately 0.8 BBOE of proved undeveloped reserves have remained undeveloped for five years or more with respect to the balance sheet date, mainly related to the Kashagan project (Kazakhstan), where development activities are progressing and production start-up is expected by the end of 2012.

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 over the next three years natural gas to third parties for a total of approximately 1,908 BCF from producing properties located in Australia, Egypt, India, Indonesia, Libya, Nigeria, Norway, Pakistan, Tunisia and the United Kingdom.

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 70% of delivery commitments.

Eni has met all contractual delivery commitments as of December 31, 2009.

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 2009, oil and natural gas production available for sale averaged 1,716 KBOE/d (liquids 1,007 KBBL/d; natural gas 4,074 mmCF/d), representing a decline of 32 KBOE/d from 2008, or 1.8%. Excluding OPEC cuts (down 28 KBOE/d) production was barely unchanged. Lower production uplifts associated with weak European gas demand, unplanned facility downtime, continuing security issues in Nigeria and mature field declines negatively affected full-year performance. Production increases were driven by continuing production ramp-ups/start-ups in Angola, Congo, Egypt, Kazakhstan, Venezuela and the Gulf of Mexico as well as the positive price impact reported in the Company s PSAs and similar contractual schemes (up 35 KBBL/d). The share of oil and natural gas produced outside Italy was 90% (89% for the year ended December 31, 2008).

Liquids production amounted to 1,007 KBBL/d for the year ended December 31, 2009 which was down 1.9% from 2008 due to OPEC cuts. Excluding OPEC cuts, the unplanned facility downtime in Libya and mature field declines, mainly in Italy and the North Sea were offset by production increases achieved in: (i) Angola due to the start-up of the Tombua-Landana project (Eni s interest 20%) and improved performance in Block 0 (Eni s interest 9.8%); (ii) Congo due to the ramp-up of the Awa Paloukou project (Eni s interest 90%); (iii) Kazakhstan due to a better performance; (iv) the Gulf of Mexico due to the start-up of the Thunderhawk (Eni s interest 25%), Pegasus (Eni s interest 58%) and Longhorn (Eni s interest 75%) projects; and (v) Venezuela due to the ramp-up of the Corocoro field (Eni s interest 26%).

Natural gas production (4,074 mmCF/d for the year ended December 31, 2009) declined from 2008 (down 1.7%). Production decreased in Libya due to lower gas demand on the European market and the mentioned technical reasons, and for mature field declines, mainly in Italy. Main increases were registered in the Gulf of Mexico, Congo due to the contribution of M Boundi gas project (Eni s interest 83%), and Croatia due to the start-up of Annamaria field (Eni s interest 50%).

Oil and gas production sold amounted to 622.8 mmBOE for the year ended December 31, 2009. The 22.9 mmBOE difference over production (645.7 mmBOE for the year ended December 31, 2009) reflected volumes of natural gas consumed in operations (19.1 mmBOE). Approximately 60% of liquids production sold (365.2 mmBBL) was destined to Eni s Refining & Marketing division (of which 17% was processed in Eni s refinery); about 30% of natural gas production sold (1,479 BCF) was destined to Eni s Gas & Power division.

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The tables below provide Eni s production, by final product sold of liquids and natural gas by geographical area for each of the last three fiscal years.

LIQUIDS PRODUCTION [1]

(KBBL/d)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2007	75	157	337	280	70	37	53	11	**1,020**
2008	68	140	338	289	69	49	63	10	**1,026**
2009	56	133	292	312	70	57	79	8	**1,007**

(1) Data includes Eni s share of production of affiliates and joint ventures accounted for under the equity method of accounting amounting to 17, 14 and 12 KBBL/d in 2009, 2008 and 2007, respectively.

NATURAL GAS PRODUCTION AVAILABLE FOR SALE [1] [2]

(mmCF/d)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2007	763	607	1,357	220	222	380	232	38	**3,819**
2008	725	588	1,661	204	227	396	304	38	**4,143**
2009	630	608	1,503	213	241	417	416	46	**4,074**

(1) Data includes Eni s share of production of affiliates and joint ventures accounted for under the equity method of accounting amounting to 29, 26 and 28 mmCF/d in 2009, 2008 and 2007, respectively.
(2) It excludes production volumes of natural gas consumed in operations. Said volumes were 300, 281 and 296 mmCF/d in 2009, 2008 and 2007, 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 97 KBOE/d, 93 KBOE/d and 75 KBOE/d in 2009, 2008 and 2007, respectively.

The tables below provide Eni s average sales prices per unit of liquids and natural gas by geographical area for each of the last three fiscal years. Also Eni s average production cost per unit of production is disclosed. The average production cost does not include any ad valorem or severance taxes.

AVERAGE SALES PRICES AND PRODUCTION COST PER UNIT

($)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2007									
Oil and condensate, per BBL	62.47	70.84	67.86	69.77	59.34	64.73	66.37	71.23	**67.70**
Natural gas, per KCF	8.58	6.71	4.60	1.21	0.41	4.34	6.69	5.94	**5.42**
Average production cost, per BOE	7.89	8.35	4.22	11.53	4.90	3.13	7.17	10.35	**6.90**
2008									
Oil and condensate, per BBL	84.87	71.90	84.71	91.58	79.06	75.08	88.69	82.80	**84.05**
Natural gas, per KCF	13.06	10.55	7.14	1.50	0.53	5.50	8.81	9.59	**8.01**
Average production cost, per BOE	9.40	8.67	3.66	15.25	5.86	3.69	10.27	8.50	**7.77**

2009									
Oil and condensate, per BBL	56.02	56.46	55.97	59.75	52.34	55.23	55.74	50.40	**56.95**
Natural gas, per KCF	9.01	7.06	5.78	1.66	0.45	4.30	4.05	8.14	**5.62**
Average production cost, per BOE	9.69	8.28	4.05	13.15	5.20	3.49	8.25	9.56	**7.49**

Drilling and other exploratory and development activities

In 2009, a total of 69 new exploratory wells[7] were drilled (37.6 of which represented Eni s share), as compared to 111 exploratory wells drilled in 2008 (58.4 of which represented Eni s share) and 81 exploratory wells drilled in 2007 (43.5 of which represented Eni s share).

Overall commercial success rate was 41.9% (43.6% net to Eni) as compared to 36.5% (43.4% net to Eni) and 40% (38% net to Eni) in 2008 and 2007, respectively.

(7) Including drilled exploratory wells that have been suspended pending further evaluation.

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In 2009, a total of 418 development wells were drilled (175.1 of which represented Eni s share) as compared to 366 development wells drilled in 2008 (155.1 of which represented Eni s share) and 349 development wells drilled in 2007 (156.7 of which represented Eni s share).

The table below provides the number of net productive and dry exploratory and development oil and natural gas wells completed in the years indicated by the Group companies and its equity-accounted entities.

NET EXPLORATION AND DEVELOPMENT DRILLING ACTIVITY

(units)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2007									
Exploratory	**4.0**	**1.4**	**15.3**	**1.7**	**0.2**	**0.2**	**9.6**	**0.6**	**33.0**
Productive	0.5		7.7	0.5		0.2	3.6		12.5
Dry [(a)]	3.5	1.4	7.6	1.2	0.2		6.0	0.6	20.5
Development	**17.0**	**27.3**	**45.8**	**18.5**	**1.3**	**37.8**	**8.4**	**0.6**	**156.7**
Productive	17.0	27.2	45.8	18.5	1.3	34.1	5.9	0.6	150.4
Dry [(a)]		0.1				3.7	2.5		6.3
2008									
Exploratory	**0.7**	**3.7**	**22.9**	**7.4**		**16.2**	**3.4**	**1.4**	**55.7**
Productive		0.7	8.7	4.0		9.4	1.4		24.2
Dry [(a)]	0.7	3.0	14.2	3.4		6.8	2.0	1.4	31.5
Development	**12.9**	**5.5**	**47.6**	**37.2**	**2.6**	**43.0**	**6.3**		**155.1**
Productive	11.3	5.5	46.4	36.4	2.6	36.5	6.3		145.0
Dry [(a)]	1.6		1.2	0.8		6.5			10.1
2009									
Exploratory	**1.0**	**4.3**	**8.6**	**2.7**		**6.2**	**4.8**	**2.2**	**29.8**
Productive		4.1	4.8			2.3	1.0	0.8	13.0
Dry [(a)]	1.0	0.2	3.8	2.7		3.9	3.8	1.4	16.8
Development	**18.3**	**12.5**	**41.1**	**37.7**	**3.8**	**42.9**	**16.6**	**2.2**	**175.1**
Productive	18.3	12.5	40.7	35.8	3.8	38.6	15.6	2.2	167.5
Dry [(a)]			0.4	1.9		4.3	1.0		7.6

(a) A dry well is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas sufficient quantities to justify completion as an oil or gas well.

Present activities

The table below provides the number of exploratory and development oil and natural gas wells in the process of being drilled by the Group companies and its equity-accounted entities as of December 31, 2009. A gross well is a well in which Eni owns a working interest.

DRILLING ACTIVITY IN PROGRESS

(units)	Italy	Kazakhstan	Americas	Total

		Rest of Europe	North Africa	West Africa		Rest of Asia		Australia and Oceania	
As of December 31, 2009 Exploratory (a)									
Gross	6.0	25.0	26.0	60.0	13.0	19.0	22.0	1.0	**172.0**
Net	4.4	6.6	18.6	15.4	2.3	8.8	8.4	1.0	**65.5**
Development									
Gross	6.0	8.0	16.0	23.0	2.0	13.0	47.0	1.0	**116.0**
Net	5.8	1.2	6.9	8.2	0.7	6.2	12.1	0.1	**41.2**

(a) Includes temporary suspended wells pending further evaluation.

Oil and gas properties, operations and acreage

As of December 31, 2009, Eni s mineral right portfolio consisted of 1,246 exclusive or shared rights for exploration and development in 40 countries on five continents for a total acreage of 347,862 square kilometers of which 41,794 square kilometers was developed acreage and 306,068 square kilometers was undeveloped acreage.

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In 2009, total net acreage increased mainly due to: (i) the acquisition of a 27.5% interest in the Alliance area, in Northern Texas from Quicksilver Resources Inc and of a 37.8% interest in the Sanga Sanga license in Indonesia, both in the development of non-conventional gas resources; (ii) the awarding of the giant Zubair oil field (Eni s interest 32.8%); and (iii) new leases in Angola, China, Ghana, the Gulf of Mexico, India, Norway and Yemen for a total acreage of approximately 40,000 square kilometers net to Eni.

Main decreases were in Mali due to the release of exploration licenses covering an undeveloped acreage of 100,000 square kilometers. Other exploration licenses were released in Congo, Egypt, Italy, Morocco, Norway, Russia, the United Kingdom and the United States mainly related to undeveloped areas.

The table below provides certain information about the Company s oil and gas properties. It discloses 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, 2009. A gross acreage is one in which Eni owns a working interest.

	December 31, 2008	December 31, 2009						
	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	**30,511**	**315**	**17,918**	**33,643**	**51,561**	**11,794**	**19,813**	**31,607**
Italy	**20,409**	**167**	**11,641**	**15,537**	**27,178**	**9,692**	**12,346**	**22,038**
Rest of Europe	**10,102**	**148**	**6,277**	**18,106**	**24,383**	**2,102**	**7,467**	**9,569**
Croatia	988	2	1,975		1,975	987		987
Norway	3,861	51	2,277	8,907	11,184	338	3,074	3,412
United Kingdom	1,450	89	2,025	3,140	5,165	777	692	1,469
Other countries	3,803	6		6,059	6,059		3,701	3,701
AFRICA	**249,672**	**276**	**70,121**	**230,549**	**300,670**	**19,865**	**138,884**	**158,749**
North Africa	**31,088**	**119**	**30,820**	**54,725**	**85,545**	**13,431**	**32,580**	**46,011**
Algeria	909	38	2,152	17,458	19,610	727	16,517	17,244
Egypt	9,741	57	4,445	18,652	23,097	1,571	6,757	8,328
Libya	18,164	13	17,947	18,427	36,374	8,951	9,214	18,165
Tunisia	2,274	11	6,276	188	6,464	2,182	92	2,274
West Africa	**156,557**	**151**	**39,301**	**98,600**	**137,901**	**6,434**	**54,090**	**60,524**
Angola	3,323	67	4,532	16,317	20,849	590	2,803	3,393
Congo	8,244	25	1,865	13,724	15,589	991	7,197	8,188
Gabon	7,615	6		7,615	7,615		7,615	7,615
Ghana		2		2,300	2,300		1,086	1,086
Mali	128,801	1		47,500	47,500		31,668	31,668
Nigeria	8,574	50	32,904	11,144	44,048	4,853	3,721	8,574
Other countries	**62,027**	**6**		**77,224**	**77,224**		**52,214**	**52,214**
ASIA	**93,710**	**80**	**18,924**	**204,274**	**223,198**	**6,369**	**119,272**	**125,641**
Kazakhstan	**880**	**6**	**324**	**4,609**	**4,933**	**105**	**775**	**880**
Rest of Asia	**92,830**	**74**	**18,600**	**199,665**	**218,265**	**6,264**	**118,497**	**124,761**
China	192	7	237	18,461	18,698	39	18,283	18,322
East Timor	9,779	5		9,999	9,999		7,999	7,999
India	9,091	14	303	27,861	28,164	143	9,946	10,089
Indonesia	17,316	12	1,735	25,940	27,675	656	15,863	16,519

Iraq		1	1,950		1,950	640		640
Iran	820	4	1,456		1,456	820		820
Pakistan	18,855	21	9,122	24,782	33,904	2,708	15,493	18,201
Russia	3,891	5	3,597	3,039	6,636	1,058	1,265	2,323
Saudi Arabia	25,844	1		51,687	51,687		25,844	25,844
Turkmenistan	200	1	200		200	200		200
Yemen	3,598	2		23,296	23,296		20,560	20,560
Other countries	3,244	1		14,600	14,600		3,244	3,244
AMERICAS	**12,043**	**558**	**4,737**	**17,234**	**21,971**	**3,090**	**8,433**	**11,523**
Brazil	1,389	2		1,389	1,389		1,067	1,067
Ecuador	2,000	1	2,000		2,000	2,000		2,000
Trinidad & Tobago	66	1	382		382	66		66
United States	6,648	543	1,977	9,120	11,097	926	5,524	6,450
Venezuela	614	3	378	1,178	1,556	98	516	614
Other countries	1,326	8		5,547	5,547		1,326	1,326
AUSTRALIA AND OCEANIA	**29,558**	**17**	**1,057**	**48,216**	**49,273**	**676**	**19,666**	**20,342**
Australia	29,520	16	1,057	47,452	48,509	676	19,628	20,304
Other countries	38	1		764	764		38	38
Total	**415,494**	**1,246**	**112,757**	**533,916**	**646,673**	**41,794**	**306,068**	**347,862**

(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 interests as of December 31, 2009. 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 7,181 (2,417.2 of which represent Eni s share).

PRODUCTIVE OIL AND GAS WELLS

(units)	Italy	Rest of Europe	North Africa	West Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
Number of productive wells as of Dec. 31, 2009 [(a)]									
Oil wells									
Gross	185.0	384.0	1,103.0	2,764.0	85.0	355.0	125.0	4.0	5,005.0
Net	145.7	64.5	469.2	474.3	27.6	255.1	56.3	2.6	1,495.3
Gas wells									
Gross	481.0	198.0	120.0	501.0		658.0	207.0	11.0	2,176.0
Net	421.1	75.2	49.1	36.6		264.3	72.6	3.0	921.9

(a) Includes approximately 2,144 gross (633 net) multiple completion wells (more than one producing into the same well bore).

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 2009, Eni s oil and gas production amounted to 165 KBOE/d. Eni s activities in Italy are deployed in the Adriatic 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.

As part of the optimization process of Eni s upstream portfolio, management approved a plan for rationalizing Eni s mineral activities in Italy by establishing three new companies to which certain of the Company s assets have been contributed. The selected assets have different geographical locations: a first group of assets that are located in Northern Italy (Pianura Padana and Emilia Romagna) have been contributed to Società Padana Energia SpA; a second group with assets located in central Italy (Marche, Abruzzo, Molise) to Società Adriatica Idrocarburi SpA; lastly certain assets in southern Italy (Crotone area) have been contributed to

Società Ionica Gas SpA. Negotiations are firmly underway for the sale of the two companies, Società Padana Energia SpA and Società Adriatica Idrocarburi SpA.

The Adriatic Sea represents Eni s main production area in Italy, accounting for 46% of Eni s domestic production in 2009. Main operated fields are Barbara (98 mmCF/d net to Eni), Angela-Angelina (48 mmCF/d), Porto Garibaldi (39 mmCF/d), Cervia (46 mmCF/d) and Tea-Arnica-Lavanda (37 mmCF/d).

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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 24 production wells of the 47 foreseen by the sanctioned development plan and is supported by the Viggiano oil center with a treatment capacity of 104 KBBL/d. Oil produced is carried to Eni s refinery in Taranto via a 136-kilometer long pipeline. Gas produced is treated at the Viggiano oil center and then delivered to the national grid system. In 2009, the Val d Agri concession produced 78 KBOE/d (42 net to Eni) representing 25% of Eni s production in Italy.

Eni is the operator of 15 production concessions onshore and offshore in Sicily. Its main fields are Gela, Ragusa, Giaurone, Fiumetto and Prezioso, which in 2009 accounted for 10% of Eni s production in Italy.

Full year development activities mainly related to: (i) the completion of the first development phase in the Val d Agri concession through the connection to the oil treatment plant of the first wells located in the Cerro Falcone, with a production of 6 KBOE/d; (ii) the start-up of LPT Tresauro oil field in Sicily and the installation of a production platform on Annamaria B where production started in March 2010; and (iii) production optimization activities on producing fields by means of sidetrack, work over and rigless activities (Annalisa, Antares, Barbara, Cervia, Giovanna, Gela, Luna and Trecate fields).

Offshore activities in Sicily related to the development of three recent gas discoveries (Panda, Argo and Cassiopea). Start-up is expected in 2013.

In the medium-term, management expects production in Italy to remain stable at the current level due to the production ramp-up of the Val d Agri fields and ongoing new field projects and continuing production optimization activities designed to counteract mature field decline.

Rest of Europe

Eni s operations in the Rest of Europe are conducted mainly in Croatia, Norway and the United Kingdom. In 2009, the Rest of Europe accounted for 14% of Eni s total worldwide production of oil and natural gas.

Croatia. Eni has been present in Croatia since 1996. In 2009, Eni s production of natural gas averaged 92 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 Ivana, Ika & Ida, Marica and Katarina operated by Eni through a 50/50 joint operating company with the Croatian oil company INA.

The fields start-up in 2009 are: (i) Annamaria (Eni s interest 50%), with a production of approximately 13 mmCF/d net to Eni; and (ii) Irina (Eni s interest 50%) and Vesna (Eni s interest 50%), with an overall production at approximately 3 mmCF/d net to Eni.

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Exploration activities yielded positive results with the Ika SW 2 appraisal well, which confirmed the mineral potential of the area.

Norway. Eni has been operating in Norway since 1964. 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 2009.

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 few years with possible extensions.

In May 2009 following an international bid procedure Eni was awarded the operatorship of exploration licenses PL 533 (Eni s interest 40%) and PL 529 (Eni s interest 40%) in addition to a 30% stake in PL 532 in the Barents Sea.

Eni holds interests in 6 production areas in the Norwegian Sea. The principal producing fields are Aasgard (Eni s interest 14.82%), Kristin (Eni s interest 8.25%), Heidrun (Eni s interest 5.12%), Mikkel (Eni s interest 14.9%) and Norne (Eni s interest 6.9%), which in 2009 accounted for 65% of Eni s production in Norway. Full year production start-up was achieved in: (i) the Yttergryta (Eni s interest 9.8%) field, with a production of approximately 71 mmCF/d; and (ii) the Tyrihans (Eni s interest 6.23%) field, with a production of approximately 3 KBBL/d. Development activities progressed in recent oil and gas discoveries near the Aasgard field (Eni s interest 14.82%). In particular the development plan of the Morvin discovery (Eni s interest 30%) provides linkage to existing production facilities that will be upgraded. Production start-up is expected in 2010 with peak production at 12 KBOE/d net to Eni in 2014.

Eni holds interests in four 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 2009 produced approximately 56 KBOE/d net to Eni and accounted for 44% of Eni s production in Norway. The license expires in 2028, and extension negotiations are ongoing. Ongoing projects aim at maintaining and optimizing production at Ekofisk by means of infilling wells, the development of the South Area, upgrading of existing facilities and optimization of water injection.

Currently Eni is only performing exploration activities in Barents Sea. Operations in this area are focused on the appraisal of the mineral potential of the large Goliat discovery made in 2000 at a water depth of 370 meters in PL 229 (Eni operator with a 65% interest) aimed at its commercial development. The license expires in 2042. The project is progressing according to schedule. Commencement is expected in 2013 with a production plateau at 100 KBBL/d. In 2009, the final investment decision of the Goliat project was sanctioned.

Exploration activities yielded positive results in the Prospecting License 128 (Eni s interest 11.5%) with the Dompap gas discovery. Appraisal activities are underway.

United Kingdom. Eni has been present in the United Kingdom since 1964. Eni s activities are carried out in the British section of the North Sea, in the Irish Sea and in some areas East and West of the Shetland Islands. In 2009 Eni s net production of oil and gas averaged 100 KBOE/d.

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

Eni holds interests in 12 production areas in the British section of the North Sea. The main fields are Elgin/Franklin (Eni s interest 21.87%), the J-Block (Eni s interest 33%), Andrew (Eni s interest 16.21%), Farragon (Eni s interest 30%), the Flotta Catchment Area (Eni s interest 20%), Mac-Culloch (Eni s interest 40%) and West

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Franklin (Eni s interest 21.87%), which in 2009 accounted for 61% of Eni s production in the United Kingdom. Development activities consist of infilling actions at the Elgin/Franklin, Mac-Culloch (Eni s interest 40%) and Jade (Eni s interest 7%) fields to maintain production levels. Pre-development activities are underway at the following discoveries: (i) the Burghley field (Eni s interest 21.92%) with expected start-up in 2010; (ii) the Kinnoul oil and gas field (Eni s interest 16.67%) to be developed in synergy with the production facilities of the Andrew field (Eni s interest 16.21%) and expected start-up in 2012; (iii) the Jasmine gas field (Eni s interest 33%) with expected start-up in 2012; and (iv) the Mariner field (Eni s interest 8.89%) with expected start-up in 2015.

Eni holds a 53.9% interest in 6 production fields in the Liverpool Bay area in the Eastern section of the Irish Sea. The main fields are Douglas, Hamilton and Lennox and their extension which in 2009 accounted for 21% of Eni s production in UK. Upgrades to the facilities are underway.

Eni holds interest in 6 production permits located east of the Shetland Islands. The main fields are Ninian (Eni s interest 12.94%) and Magnus (Eni s interest 5%), which in 2009 accounted for 4% of Eni s production in the United Kingdom. In 2009, maintenance and optimization actions were performed with the drilling of infilling wells.

Exploration activities yielded positive results in Block 22/25a (Eni s interest 16.95%) with the Culzean gas discovery near the Elgin/Franklin producing field (Eni s interest 21.87%). A study of the development activities is underway.

North Africa

Eni s operations in North Africa are conducted in Algeria, Egypt, Libya and Tunisia. In 2009, North Africa accounted for 32% of Eni s total worldwide production of oil and natural gas.

Algeria. Eni has been present in Algeria since 1981. In 2009, Eni s oil and gas production averaged 80 KBOE/d. Operating activities are located in the Bir Rebaa area in the South-Eastern desert and include the following exploration and production blocks: (i) Blocks 403 a/d (Eni s interest 100%); (ii) Blocks 401a/402a (Eni s interest 55%); (iii) Blocks 403 (Eni s interest 50%) and 404a (Eni s interest 12.25%); and (iv) under development Blocks 212 (Eni s interest 22.38%), 208 (Eni s interest 12.25%) and 405b (Eni s interest 75%), the latter purchased in 2008 from Canadian company First Calgary.

Relevant authorities confirmed the acquisition of the operatorship of the Kerzaz exploration area (Blocks 319a, 321a and 316b) covering a total acreage of 16,000 square kilometers. Exploration activities are underway.

Exploration and production activities in Algeria are regulated by Production Sharing Agreements (PSAs) and concession contracts.

Production in Block 403a/d is supplied mainly by the HBN and Rom and satellite fields which represented approximately 28% of Eni s production in Algeria in 2009. The main project underway is the Rom Integrated project, designed to develop the Rom and satellites reserves (Zea, Zek and Rec) following the mineral potential revaluation. Current production is collected at the Rom Central Production Facility (CPF) and delivered to the treatment plant in Bir Rebaa North. Drilling and work over activities were started in 2009. An export pipeline and a new multiphase pumping system are underway in compliance with applicable Country law to reduce gas flaring.

Production in Blocks 401a/402a is supplied mainly by the Rod and satellite fields and accounted for approximately 22% of Eni s production in Algeria in 2009. Infilling activities are being performed in order to maintain the current production plateau.

The main fields in Block 403 are BRN, BRW and BRSW which accounted for approximately 16% of Eni s production in Algeria in 2009. Exploration activities for appraising the mineral potential of the area are planned.
In Block 405b, the development activity relates to the MLE and CAFC integrated project. During 2009 the MLE final investment decision was sanctioned. This project provides the construction of a NGL plant with a capacity of 350 mmCF/d. Production start-up is expected in November 2011. The CAFC final investment decision will be sanctioned in 2010. The CAFC project will provide the construction of an oil treatement plant with a capacity of 35 KBBL/d and installation of water/gas injection systems. The development of the two fields will ensure a production plateau of approximately 33 KBOE/d net to Eni by 2012. Drilling activities are underway. In 2009 the EPC contract for the construction of a gas treatment plant, gathering and exporting facilities has been awarded. As of December 31, 2009, 11% of the project was completed. The PSA expires in 2037.

Block 208 is located south of Bir Rebaa. In 2009, the final investment decision of El Merk was sanctioned. During the year all EPC contracts for the development of facilities were awarded and drilling activity started. 24% of the project was completed and start-up is expected in 2012.

The new Algerian hydrocarbon law No. 05 of 2007 introduced a higher tax burden for the national oil company Sonatrach that requested to renegotiate the economic terms of certain PSAs in order to restore the initial economic equilibrium. Eni signed an agreement for Block 403 while negotiations are ongoing for Block 401a/402a (Eni s interest

55%) and Block 208 (Eni s interest 12.25%). At present, management is not able to foresee the final outcome of such renegotiations.

In the medium-term, management expects to increase Eni s production in Algeria to greater than 125 KBOE/d, reflecting the development and integration of the First Calgary acquired assets.

Egypt. Eni has been present in Egypt since 1954. In 2009, Eni s share of production in this country amounting to 220 KBOE/d and accounted for 13% of Eni s total annual hydrocarbon production. Eni s main producing liquid fields are located in the Belayim concession (Eni s interest 100%), in the Western Desert mainly Melehia concession (56% interest) and Ras Qattara (75% interest). Gas production mainly comes from the operated or participated concession of North Port Said (former Port Fouad, Eni s interest 100%), Baltim (50% interest), Ras el Barr (50% interest, non-operated) and el Temsah (50% interest) offshore the Nile Delta. In 2009, production from these concessions also includes a portion of liquids accounting for more than 80% of Eni s production in Egypt.

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Exploration and production activities in Egypt are regulated by concession contracts and PSAs.

In May 2009, Eni signed a cooperation agreement with Egypt s Ministry for Oil to increase and widen cooperation in development activities. The agreement provides for: (i) an extension of the concession of the giant Belayim field in the Gulf of Suez until 2030, with Eni s commitment to spending $1.5 billion over the next five years related to development expenditures, upgrading actions and operating costs; (ii) a joint study to evaluate a number of industrial initiatives to monetize the natural gas reserves at high depth; and (iii) training and knowledge management.

In 2009, in the offshore area of the Nile Delta, the North Bardawil (Eni operator with a 60% interest) and Thekah fields (Eni operator with a 50% interest) started-up by linking to El Gamil facilities with an overall production plateau at approximately 190 mmCF/d.

The basic engineering is ongoing at the Belayim field for the upgrading of water injection facilities to recover residual reserves.

Other development activities concerned the Tuna project, the second phase at the Denise field and upgrading of the el Gamil compression plant by adding new capacity to support production.

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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 is currently supplying 35 BCF/y for a twenty-year period. Natural gas supplies derived from the Taurt and Denise fields with 17 KBOE/d net to Eni of feed gas.

In the medium-term, management expects that Egypt will remain among Eni s largest oil and gas producing countries.

Libya. Eni started operations in Libya in 1959. In 2009, Eni s oil and gas production averaged 238 KBOE/d, the portion of liquids being 45%. Production activity is carried out in the Mediterranean Sea near Tripoli and in the Libyan Desert area.

Under the agreement signed in 2008 with the Libyan national oil company ("NOC"), Eni s assets have been grouped into 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) Sicily 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 Muzurk basin (161/1, 161/2&4, 176/3), 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 terms of Eni s assets in Libya have been extended until 2042 and 2047 for oil and gas properties respectively, taking into account the extension clauses.
Main development activities underway include the Western Libyan Gas project (Eni s interest 50%) for the exploitation of gas reserves ratified in the strategic agreements between Eni and NOC. In particular upgrading of plants and facilities in order to increase gas sales by 49 BCF/y was completed. Additional gas volumes are also expected to be on stream by 2015 from a portfolio of undeveloped fields. Gas production at Wafa and Bahr Essalam will be maintained by increasing compression capacity at Wafa field and drilling of additional wells in both fields.

In 2009, volumes delivered through the GreenStream pipeline were 309 BCF. In addition, 43 BCF were sold on the Libyan market for power generation and to fuel the GreenStream pipeline compression plant.

Other projects underway related to: (i) a plan to exploit flaring gas and associated condensates from the Bouri oil field (Eni s interest 50%) that will be pre-treated in the area and then delivered at the Mellitah plant for the final treatment;

and (ii) ongoing activities aimed at maintaining the El Feel field (Eni s interest 33.3%) production plateau through water injection.

In the medium-term, management expects to increase Eni s production in Libya due to the expected ramp-up of new gas developments the schedule of which will depend upon future trends in the gas market with the support of the upgrade of the GreenStream pipeline, despite mature field declines. In the medium-term Libya is expected to remain the largest producing country by volume in Eni s portfolio.

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Tunisia. Eni has been present in Tunisia since 1961. In 2009, 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 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.

The ongoing development projects mainly related to the optimization of production at the Adam, Djebel Grouz (Eni s interest 50%), Oued Zar and El Borma blocks.

The development plan of Maamoura concession (Eni operator with a 49% interest) is almost completed with early production started-up in late 2009. The Baraka (Eni operator with a 49% interest) development project is in the final stage with production peaking at 11 KBOE/d which is expected in 2010.

Exploration activities yielded positive results with four discovery wells among five drilled. In 2009 gas production was started in one well, while two more wells are expected to start-up in 2010.

In the medium-term, Eni expects production in Tunisia to increase thanks to the development of recent discoveries.

West Africa

Eni s operations in West Africa are conducted mainly in Angola, Congo and Nigeria. In 2009, West 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 2009, Eni s production averaged 125 KBOE/d. Eni s activities are concentrated in the conventional and deep offshore.

The main blocks with Eni s participation are: (i) Block 0 in Cabinda (Eni s interest 9.8%) west of the Angolan coast; (ii) Development Areas in the former Block 14 (Eni s interest 20%) in the deep offshore west of Block 0; and (iii) Development Areas in the former Block 15 (Eni s interest 20%) in the deep offshore of the Congo basin.

Eni also holds interests in other minor concessions, in particular in some areas of Block 3 (with interests varying from 12 to 15%) and in the Lianzi Development Area (former 14K/A IMI Unit Area-Eni s interest 10%). In the exploration and development phase, Eni is operator of Block 15/06 (35% interest), holds 12% interest in Block 3/05-A, 10% interest in Cabinda North (onshore) and 20% interest in the Open Areas of the Gas Project.

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

In February 2009, three agreements were finalized as part of the Memorandum of Understanding signed in August 2008 with Angola s National Oil Company Sonangol, providing for: (i) a feasibility study to assess the economics of the utilization of associated gas in feeding a grass-root onshore power plant; (ii) a joint study to evaluate and collect data on certain Angolan onshore basins in view of identifying upstream opportunities; and (iii) the design of a number of educational and training projects targeting Angolan professionals in the development of energy resources.

In 2009, production started-up at the Mafumeira field in Block 0 in the Cabinda A area (Eni s interest 9.8%) and the Landana-Tombua fields in the

Development Areas of the former Block 14. Peak production at 33 KBOE/d and 136 KBOE/d is expected in 2010 and 2011, respectively.

Within the activities for reducing gas flaring, projects progressed at the Nemba field in Block 0. Start-up is expected in 2013 reducing flared gas by approximately 85%. In 2009, the development activity of Takula field was completed. Gas flared is re-injected in the field; condensates will be shipped to the Malongo treatment plant, nearing completion.

Main projects underway in the Development Areas of former Block 15 were as follows: (i) development activities started-up at the satellites of Kizomba project-phase 1. The project provides for the drilling of 18 producing wells linked to the FPSO vessels existing in the area. Associated gas will be initially re-injected in the reservoirs in the Kizomba area, and thereafter delivered to the A-LNG liquefaction plant. Start-up is expected in 2012. Peak production at 100 KBOE/d (21 net to Eni) is expected in 2013. The second phase provides for production from nearby discoveries; and (ii) the Gas Gathering project, entailing the construction of a pipeline collecting all gas from the Kizomba, Mondo and Saxi/Batuque areas, is underway. Completion is expected in 2011.

Eni holds a 13.6% interest in the Angola LNG Ltd (A-LNG) consortium responsible for the construction of an LNG plant in Soyo, 300 kilometers north of Luanda. It has been designed with a processing capacity of about 1.1 BCF/d of natural gas and to produce 5.2 mmtonnes/y of LNG. The project has been sanctioned by relevant Angolan authorities. It envisages the development of 10,594 BCF of associated gas reserves in 30 years. Start-up is expected in the first quarter of 2012. The LNG will be delivered to the United States market at the re-gasification plant in Pascagoula currently under construction (Eni s capacity 45%, amounting to approximately 205 BCF/y) in Louisiana. Start-up is expected in late 2011.

In addition, Eni finalized another agreement with the national Angolan company and other partners to be part of a second gas consortium which will explore further potential gas discoveries (Gas project) to support the feasibility of a second LNG train. Eni is the technical advisor for this consortium, with a 20% interest.

Exploration activities yielded positive results in: (i) Block 3 (Eni s interest 12%), the Punja-4 appraisal well showed the presence of liquids and natural gas; (ii) the Development Areas of former Block 14 (Eni s interest 20%) with the Malange-2 appraisal well containing oil; (iii) the Development Areas of former Block 15 (Eni s interest 20%) with the Mondo-4 appraisal well containing oil; and (iv) Block 15/06 (Eni operator with a 35% interest) where the Cabaça Norte, Nzanza and Cinguvu discoveries showed the presence of oil and yielded 6.5 KBBL/d, 1.5 KBBL/d and 6.4 KBBL/d in test production, respectively.

In the medium-term, management expects to increase Eni s production to approximately 180 KBBL/d reflecting contributions from ongoing development projects, despite mature field declines.

Congo. Eni has been present in Congo since 1968. In 2009, production averaged 99 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%) and Loango (Eni s interest 50%), Ikalou (Eni s interest 100%), Djambala, Foukanda e Mwafi (Eni s interest 65%), Kitina (Eni s interest 35.75%), Awa Paloukou (Eni s interest 90%), M Boundi

(Eni s interest 83%) and Kouakouala (Eni s interest 75%) fields.

Other relevant producing areas are a 35% interest in the Pointe Noire Grand Fonde and PEX 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%), the Marine XII offshore permit (Eni operator with a 65% interest) and the Le Kouilou onshore permit (Eni operator with an 85% interest).

Exploration and production activities in Congo are regulated by Production Sharing Agreements.

In 2009, the development plan of Awa-Paloukou field was completed. Production start-up was 12 KBBL/d.

Activities on the M Boundi operated field moved forward with the revision of the production schemes and layout to plan application of advanced recovery techniques and a design to monetize associated gas. The permit expires in 2027. In 2009, Eni signed a long term agreement to supply associated gas from the M Boundi field to feed three facilities in the Pointe Noire area: (i) the Koilou potassium plant, owned by Canadian Company MAG Industries and under construction; (ii) the CED (Centrale Electrique du Djeno) existing power plant; and (iii) the new built CEC (Centrale Electrique du Congo - Eni s interest 20%). The facilities will also receive gas in the future from the offshore discoveries of the Marine XII permit.

The development activities to build the CEC power plant moved forward in 2009 as scheduled in the Cooperation Agreement signed by Eni and the Republic of Congo in 2007, and the start-up of the first turbo-generator occurred by the end of March 2010.

Also the studies related to the possible exploitation of unconventional oil reserves from the Tchikatanga and Tchikatanga-Makola areas have progressed, according to the cooperation agreement signed in 2008, with the particular aim to identify area where it would be possible to withstand the stringent Eni s environmental and sustainability requirements for development.

Exploration activities yielded positive results in: (i) the Marine XII permit with two discoveries wells which confirmed the mineral potential of the area. The related PSA was signed; and (ii) the Le Kouilou permit with the Zingali field, confirmed by subsequently long production test.

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 150 KBOE/d by 2013.

Ghana. On September 28, 2009, Eni acquired the operatorship of the offshore exploration permits for Cape Three Point South and Cape Three Point (Eni s interest 47.2%). Exploration activities yielded positive results in the latter with the Sankofa discovery containing oil and natural gas.

Nigeria. Eni has been present in Nigeria since 1962. In 2009, Eni s oil and gas production averaged 124 KBOE/d located mainly in the onshore and offshore of the Niger Delta.

In the development/production phase Eni is operator of onshore Oil Mining Leases (OML) 60, 61, 62 and 63 (Eni s interest 20%) and offshore OML 125 (Eni s interest 85%), OMLs 120-121 (Eni s interest 40%), holding interests in OML 118 (Eni s interest 12.5%) as well as 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 30 onshore blocks and a 12.86% interest in 5 conventional offshore blocks.

In the exploration phase Eni is operator of offshore Oil Prospecting Leases (OPL) 244 (Eni s interest 60%), OML 134 (former OPL 211 - Eni s interest 85%) 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 (former OPL 219).

Exploration and production activities in Nigeria are regulated mainly by Production Sharing Agreements and concession contracts as well as service contracts, in two blocks, where Eni acts as contractor for state owned companies.

In 2009, production from the Oyo offshore field in Blocks OML 120/121 (Eni s interest 40%) has started with peak production of 25 KBBL/d.

In Blocks OML 60, 61, 62 and 63 (Eni operator with a 20% interest), within the activities aimed at guaranteeing production to feed gas to the Bonny liquefaction plant (Eni s interest 10.4%), the development of gas reserves continued by upgrading treatment capacity at the Obiafu/Obrikom plant as well as the installation of a new treatment plant and transport facilities for carrying 155 mmCF/d net to Eni of feed gas for 20 years. To the same end the development plan of the Tuomo gas field has been progressing along with its linkage to the Ogbainbiri treatment plant.

An integrated oil and gas project is underway in the Gbaran-Ubie area. The development plan provides for the construction of a Central Processing Facility (CPF) with treatment capacity of about 1 BCF/d of gas and 120 KBBL/d of liquids, the drilling of producing wells and the construction of a pipeline to carry the gas to the Bonny liquefaction plant. The first gas is expected in the third quarter of 2010.

Eni holds a 10.4% interest in Nigeria LNG Ltd which is responsible for the management of 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 from 6 trains. The seventh unit is

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being engineered as it is in the pre-fid 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 (Eni s interest 20%). In 2009, total supplies were 1,798 mmCF/d (130 mmCF/d net to Eni corresponding to 23 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 also has a 17% interest in the Brass LNG Ltd Co for the construction of a natural gas liquefaction plant that will be built near the existing Brass terminal which is 100 kilometers west of Bonny. This plant is expected to start operating in 2015 with a production capacity of 10 mmtonnes/y of LNG corresponding to 590 BCF/y (approximately 60 net to Eni) of feed gas on 2 trains for twenty years. Supplies 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. The venture signed preliminary long-term contracts to sell the whole LNG production capacity. Eni acquired 1.67 mmtonnes/y of LNG capacity (corresponding to approximately 81 BCF/y). The LNG will be delivered to the United States market mainly at the re-gasification plant in Cameron, located in Louisiana. Eni s capacity amounts to approximately 201 BCF/y. Front end engineering activities continued during 2009 and the final investment decision is expected at the end of 2010.

In the medium-term, management expects to increase Eni s production in Nigeria to approximately 190 KBOE/d, reflecting in particular 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 2009, Eni s operations in Kazakhstan accounted for 7% of its total worldwide production of oil and natural gas.

In November 2009, Eni signed a co-operation agreement with the Kazakh national oil company KazMunaiGas. This agreement envisages joint studies and activities to be performed on: (i) the preliminary evaluation of the Isatay and Shangala exploration areas located in the Northern Caspian Sea; (ii) gas utilization in Kazakhstan; and (iii) a number of industrial initiatives including the upgrading of the Pavlodar refinery, in which KMG holds a majority interest.

Kashagan. Eni holds a 16.81% participating interest in the NCSPSA. The NCSPSA defines terms and conditions for the exploration and development activities to be performed in an area encompassing approximately 4,600 square kilometers. The Kashagan field was discovered in the northern section of the contractual area in the year 2000. Management believes this field contains a large amount of hydrocarbon resources which will be developed in phases. The PSA on Kashagan 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 in favor of the Kazakh national oil company, KazMunaiGas. The Kazakh partner will pay the other co-venturers an aggregate amount of $1.78 billion for the transaction. Eni partners of the international 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%.

Exploration and development activities in the Kashagan field and in 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 the execution of the subsequent development phases of the project. The North Caspian Operating Company (NCOC) BV, participated by the seven partners of the consortium has taken over the operatorship of the project in January 2009. Subsequently development, drilling and production activities have been delegated by NCOC BV to the main partners of the consortium: Eni will retain responsibility for the Phase 1 of the project (the so-called Experimental Program) and for the onshore operations of Phase 2.

In conjunction with the agreement signed in October 2008, the Kazakh authorities approved a new schedule which foresees the production start-up by the end of 2012 and a revised expenditure budget of Phase 1 of the project, amounting to $32.2 billion (excluding general and administrative expenses) of which: $25.4 billion for the execution of the original scope of work of Phase 1 (tranches 1 and 2) and the remaining portion for the execution of tranche 3 and construction of certain exporting facilities. Eni will fund those investments in proportion to its participating interest of 16.81%. Management is targeting first oil by the end of 2012. In the following 12-15 months processing facilities and compression units for gas re-injection will be entirely commissioned to enable an installed production capacity of 370 KBBL/d in 2014. Afterwards, production capacity of Phase 1 is expected to step up to 450 KBBL/d, leveraging on availability of further compressor capacity for gas re-injection associated with the Phase 2 offshore facilities.

Phase 2 is currently in the stage of Front End Engineering Design (FEED).

The development plan of the Kashagan field was originally approved by the Kazakh authorities in February 2004, contemplating a phased development scheme including partial gas re-injection in the reservoir to enhance the recovery factor of the crude oil. The sanctioned plan budgeted expenditures amounting to U.S. $10.3 billion (in 2007 real terms) to develop Phase 1, with a target production level of 300 KBBL/d. First oil was originally scheduled to be produced by the end of 2008. Eni was expected to fund these expenditures according to its participating interest in this project. On June 29, 2007, Eni, as operator, submitted to the relevant Kazakh authorities amendments to the sanctioned development plan. These amendments rescheduled the production start-up to 2010 and estimated development expenditures for Phase 1 at U.S. $19 billion. As outlined above the amended development plan sanctioned in October 2008 forecasts production start-up in late 2012 and an expenditure budget for Phase 1 amounting to $25.4 billion. The production delay and cost overruns were driven by a number of factors, such as: (i) depreciation of the U.S. dollar versus the euro and other currencies; (ii) cost price escalation of goods and services required to execute the project; (iii) an original underestimation of the costs and complexity to operate in the North Caspian Sea due to lack of benchmarks; and (iv) design changes to enhance the operability and safety standards of the offshore facilities.

Management believes that the magnitude of the reserves base, the results of the well tests conducted and the findings of subsurface studies completed so far support expectations for a full field production plateau of 1.5 mmBBL/d. The achievement of the full field production plateau will require a relevant amount of expenditures in addition to the development expenditures needed to complete the execution of Phase 1. However, taking into account that future development expenditures will be incurred over a long time period, 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 upgrade or to build the infrastructures needed for exporting the production to international markets, for which various options are currently under review by the Consortium. These include: (i) the use of existing infrastructure, such as the Caspian Pipeline Consortium pipeline (Eni s interest 2%) and the Atyrau-Samara pipeline, both of which are expected to undergo a capacity expansion; and (ii) construction of transportation systems needed for phases subsequent to the experimental program. In this respect, it is worth mentioning the project aimed at building a line connecting the onshore Bolashak production center with the Baku-Tbilisi-Cehyan pipeline (where Eni holds an interest of 5% corresponding to the right to transport 50 KBBL/d) through the KCTS pipeline to Kuryk and a further shipping across the Caspian Sea to Baku and the construction of a new transport system linking Samsun on the Turkish coast of the Black Sea to Cehyan on the Mediterranean coast in order to bypass the congested Turkish Straits of Bosporus and Dardanelles.

As of December 31, 2009, Eni s proved reserves booked for the Kashagan field amounted to 588 mmBOE, recording a decrease of 6 mmBOE with respect to 2008.

As of December 31, 2008, Eni s proved reserves booked for the Kashagan field amounted to 594 mmBOE determined according to Eni s participating interest of 16.81%, recording an increase of 74 mmBOE with respect to 2007 despite the divestment of a 1.71% stake in the Kashagan project following the finalization of the agreements implementing the new contractual and governance framework of the project.

As of December 31, 2007, Eni s proved reserves booked for the Kashagan field amounted to 520 mmBOE, recording a decrease of 76 mmBOE with respect to 2006 mainly due to the impact of increased year-end oil prices on reserve entitlements in accordance with the PSA scheme. Proved reserves for the field as of December 31, 2007 were determined according to Eni s then current participating interest of 18.52%.

As of December 31, 2009, the aggregate costs incurred by Eni for the Kashagan project capitalized in the consolidated financial statements amounted to $4.5 billion (euro 3.1 billion at the EUR/USD exchange rate of December 31, 2009). This capitalized amount included: (i) $3.4 billion relating to expenditures incurred by Eni for the development of the oilfield; and (ii) $1.1 billion relating primarily to accrue finance charges and expenditures for the acquisition of interests in the North Caspian Sea PSA consortium from exiting partners upon exercise of pre-emption rights in previous years.

As of December 31, 2008, the aggregate costs incurred by Eni for the Kashagan project capitalized in the consolidated financial statements amounted to $3.3 billion (euro 2.4 billion at the EUR/USD exchange rate of December 31, 2008) net of the divestment of a 1.71% stake in the Kashagan project following the finalization of the agreements implementing the new contractual and governance framework of the project ($0.4 billion). This capitalized amount included: (i) $2.3 billion relating to expenditures incurred by Eni for the development of the oilfield; and (ii) $1 billion relating primarily to accrued 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 in West onshore Kazakhstan, Karachaganak is a liquid and gas field. Operations are conducted by the Karachaganak Petroleum Operating consortium (KPO) and are regulated by a Production Sharing Agreement lasting 40 years, until 2037. Eni and British Gas are co-operators of the venture both with a 32.5% interest.

In 2009, production of the Karachaganak field averaged 238 KBBL/d of liquids (70 net to Eni) and 883 mmCF/d of natural gas (241 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 two thirds of liquid production are stabilized at the Karachaganak Processing Complex (KPC) with a capacity in excess of 150 KBBL/d and exported to Western markets through the Caspian Pipeline

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

The execution of a fourth oil treatment unit has been progressing towards completion and will enable to increase the export to western markets of currently non-stabilized liquids delivered to the Orenburg terminal. The construction of the Uralsk Gas Pipeline is ongoing. This new infrastructure, with a length of 150 kilometers, will link the Karachaganak field to the Kazakhstan gas network. Start-up is expected in 2010.

The engineering activities of Phase 3 of the Karachaganak project identified a staged approach to best develop the field. The project provides for the installation of gas producing and re-injection facilities to increase gas sales at the Orenburg plant up to 565 BCF/y and the liquids production up to approximately 14 mmtonnes/y. With the view to sanctioning the Phase 3, technical and commercial discussions with the relevant authority are ongoing.

As of December 31, 2009, Eni s proved reserves booked for the Karachaganak field amounted to 633 mmBOE, recording a decrease of 107 mmBOE with respect to 2008 in connection to a downward revisions due to the impact of higher oil prices and the production of the year.

As of December 31, 2008, Eni s proved reserves booked for the Karachaganak field amounted to 740 mmBOE, recording an increase of 200 mmBOE with respect to 2007 as a result of the upward revisions of previous estimates that were mainly related to higher entitlements reported in PSA resulting from lower year end oil prices from a year ago.

As of December 31, 2007, Eni s proved reserves booked for the Karachaganak field amount to 541 mmBOE, a decrease of 82 mmBOE with respect to 2006 as a result of downward and upward revisions of previous estimates. Downward revisions mainly related to an adverse price impact in determining volume entitlements in accordance with the PSA scheme. These negative revisions were partly offset by upward revisions that mainly related to the finalization of a revised gas sale contract.

Rest of Asia

In 2009, 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 2009 Eni s production amounted to 8 KBOE/d.

Exploration and production activities in China are regulated by Production Sharing Agreements.

Hydrocarbons are produced from the offshore blocks 16/08 and 16/19 operated by the CACT-Operating Group (Eni s interest 16.33%). Oil, which is sold into the domestic market, is produced from seven platforms connected to a FPSO; the greater portion of Eni oil production derives from the HZ25-4 field (Eni s interest 49%). Natural gas production from the HZ21-1 field is delivered through a sealine to the Zhuhai Terminal, close to Macao and sold to the Chinese National

Company CNOOC.

During 2009, development activities were mainly focused on the HZ25-4 and the HZ25-3/1 fields. The development of the HZ25-4 field, on stream since 2007, continued with the drilling of additional producing wells as planned, while on HZ25-3/1, following the installation of the production platform, the drilling of the producing wells continued.

In 2009 Eni signed the PSAs related to Blocks 3/27 and 28/20 located in the South China Sea covering a total acreage of 18,194 square kilometers. Eni s participating interest in the exploration stage is equal to 100%.

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India. Eni has been present in India since 2005.

In 2008, Eni acquired control of the Indian company Hindustan Oil Exploration Co Ltd (HOEC) following the execution of a mandatory tender offer on a 20% stake of the HOEC share capital. The mandatory offer was associated with Eni s acquisition of a 27.18% of HOEC as part of the Burren Energy deal.

In 2009 production started-up from the PY-1 gas field which is part of the assets acquired from Hindustan Oil Exploration Co Ltd. Gas production is sold to the local national oil company.

Other activities are related to the exploration of the onshore Block RJ-ONN-2003/1 (Eni operator with a 34% interest) and offshore Blocks AN-DWN-2003/2 (Eni operator with a 40% interest) and MN-DWN-2002/1 (Eni s interest 34%).

Indonesia. Eni has been present in Indonesia since 2001. In 2009, Eni s production, mainly composed of gas, amounted to 18 KBOE/d. Activities are concentrated in the eastern offshore and onshore of Borneo, the offshore Sumatra, and the offshore and onshore area of the West Timor; in total, Eni holds interest in 12 blocks.

In November 2009, Eni was awarded a 37.8% participating interest in the new Sanga Sanga PSA in connection with coal bed methane (CBM) production. The PSA defines terms and conditions for the exploration, development and production of gas from shallow levels of coal within a contractual area that mostly coincides with the one regulated by the Sanga Sanga PSA for the production of conventional hydrocarbons. Exploration activity start-up is expected in 2010. If the results of these preliminary activities are positive, the project will benefit from the opportunities of synergy provided by the existing production and treatment facilities in Sanga Sanga and the Bontang LNG plant.

Exploration and production activities in Indonesia are regulated by PSAs.

In 2009, the development plan of the Jau field in the Krueng Mane Block (Eni s interest 75%) located offshore of Sumatra was submitted to the relevant Authority. Eni is evaluating major development opportunities for the development of the oil and gas discoveries in the Bukat permit (Eni operator with a 66.25% interest) and for the five gas discoveries in the Kutei Deep Water Basin area (Eni s interest 20%).

Positive results in the exploration activity were achieved with the Jangkrik gas discovery located in the Muara Bakau Block (Eni s interest 55%) offshore Borneo.

Iraq. On January 22, 2010 Eni leading a consortium of international companies and the Iraqi national oil companies, South Oil Co and Missan Oil

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Co signed a technical service contract, with a 20-year term with an option for further 5 years, to develop the Zubair oil field (Eni 32.8%). The field was awarded in October 2009 to the Eni-led consortium following a successful first bid round and was offered under a competitive bid process beginning on June 30, 2009. The partners of the project plan to gradually increase production to a target plateau level of 1.2 mmBOE/d over the next six years. The contract provides that the consortium will earn a remuneration fee on the incremental oil production once production has been raised by 10 percent from its current level of approximately 180 KBBL/d and will recover its expenditures through a cost recovery mechanism based on the revenues from the field s production.

The field development will take place in two phases: (i) the Rehabilitation Plan, which will improve the existing production rate to gain full knowledge of the reservoir and (ii) the Redevelopment Plan, which will increase production to the target plateau.

Iran. Eni has been present in Iran since 1957. Eni s activities in Iran are currently limited mainly to the implementation of two buyback contracts signed between 2000 and 2001. Specifically, in 2009 activities were executed on the Darquain project which related to plant commissioning and start-up in view of making formal hand over of operations to local partners at some point in 2010. Darquain was the sole Eni-operated project in the country. With regard to another project, Eni s involvement essentially consists of being reimbursed for its past investments. In 2009, Eni s production in Iran was 35 KBOE/d, approximately 2% of the Group s worldwide production. Eni does not believe that its activities in Iran have a material impact on the Group s results.

Pakistan. Eni has been present in Pakistan since 2000. In 2009 Eni s production averaged 56 KBOE/d and is mainly gas.

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

In March 2009, Eni signed a Protocol for Cooperation with the government of Pakistan which foresees the possible development of a number of important upstream, midstream and downstream projects in the country. This deal is in line with Eni s strategy of consolidating its position as principle international operator in the country. Eni will provide its know-how as well as new technologies developed in the oil and gas sector.

Eni s main permits in the Country are Bhit (Eni s interest 40%), Sawan (Eni s interest 23.68%) and Zamzama (Eni s interest 17.75%), which in 2009 accounted for 88% of Eni s production in Pakistan

Development activities were focused on: (i) the Bhit field with the ongoing installation of a compressor plant aimed at maintaining the current production plateau; (ii) the Sawan field where construction activity of a compressor plant is ongoing; and (iii) the Zamzama permit where activities on the third treatment plant for the production of high calorific value (HCV) gas are aimed at optimizing current production. During the year additional activities were targeted at optimizing production from the Bhit, Sawan and Kadanwari fields by drilling additional wells.

Positive results from exploration activity were obtained with discoveries in the Badhra (Eni operator with a 40% interest), Kadanwari (Eni operator with an 18% interest) and Miano (Eni s interest 15%) areas. The start-up timing of these recent discoveries will benefit from the proximity to existing producing facilities.

Russia. Eni has been present in Russia since 2007 following the acquisition of Lot 2 in the liquidation of Yukos.

In September 2009, Eni and its Italian partner Enel in the 60-40% owned joint-venture OOO SeverEnergia completed the divestment of the 51% stake in the venture to Gazprom based on the call option exercised by the Russian company. Currently Eni s interest is 29.4%. Eni collected the total cash consideration ($940 million), 25% of which had been collected at the transaction date and the remaining 75% on March 31, 2010. A gain in amount of euro 100 million was recognized in the profit and loss account for the year ended December 31, 2009. The gain was associated with interest income at an annual rate of 9.4% accruing on the initial investment in the venture when it was acquired on April 4, 2007 based on the contractual arrangements between Eni and Gazprom. The three partners are committed to producing the first gas from the Samburskoye field by June 2011, targeting a production plateau of 150 KBOE/d within two years from the start of production.

In April 2009, Gazprom exercised its call option to purchase a 20% interest in OAO Gazprom Neft held by Eni based on the existing agreements between the two partners. The exercise price of the call option collected by Eni on April 24, 2009 amounted to euro 3,070 million is equal to the price ($3.7 billion) outlined in the bid procedure for the assets of the bankrupt Russian company Yukos as adjusted by subtracting dividends distributed and adding the contractual yearly remuneration of 9.4% on the capital employed and financing collateral expenses. Eni and Gazprom signed new cooperation agreements targeting certain development projects to be conducted jointly in Russia and other countries of interest.

Americas

In 2009, Eni s operations in America area accounted for 9% of its total worldwide production of oil and natural gas.

Trinidad and Tobago. Eni has been present in Trinidad and Tobago since 1970. In 2009, Eni s production averaged 67 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 and Hibiscus gas fields in the North Coast Marine Area 1 Block (Eni s interest 17.4%). Production is supported by fixed platforms linked to the Hibiscus treatment facility. Natural gas is used to feed trains 2, 3 and 4 of the Atlantic LNG liquefaction plant under long-term contracts. LNG production is sold in the United States, Spain and the Dominican Republic.

The main development project relates to the Poinsettia, Bougainvillea and Heliconia fields in the North Coast Marine Area 1. The project provides for the installation of a production platform on the Poinsettia field and the linkage to the Hibiscus treatment facility which was already upgraded. The drilling program on Heliconia and Bougainvillea fields is underway. Start-up is expected in 2010. In 2009 production started at the Poinsettia field.

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 2009, Eni s oil and gas production is mainly derived from the Gulf of Mexico with an average of 117 KBOE/d.

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

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Eni holds interests in 370 exploration and production blocks in the Gulf of Mexico of which 60% are operated by Eni.

The main fields operated by Eni with a 100% interest are Allegheny, East Breaks and Morphet as well as Devils Towers, Triton and Goldfinger (Eni operator with a 75% interest). Eni also holds interests in the Medusa (Eni s interest 25%), Europa (Eni s interest 32%), and King Kong (Eni operator with a 56% interest) fields.

In May 2009, Eni signed a strategic alliance with Quicksilver Resources Inc, an independent U.S. natural gas producer, to acquire a 27.5% interest in the Alliance area, located in the Fort Worth basin of Texas. The acquisition for cash consideration amounting to $280 million includes gas shale production assets with 40 mmBBL of resources base. Production plateau at 10 KBOE/d net to Eni is expected in 2011.

In 2009, production start-up was achieved in the Gulf of Mexico as follows: (i) the Thunderhawk field (Eni s interest 25%) through the drilling of underwater wells and linkage to a semi submersible production unit with a treatment capacity of 45 KBBL/d of oil and about 71 mmCF/d of natural gas; (ii) the Longhorn field (Eni s interest 75%) through the drilling of underwater wells and installation of production platform with a treatment capacity of approximately 247 mmCF/d; and (iii) the Leo field (Eni s interest 75%) by means of the linkage to the Longhorn production facilities.

The development plan of the Appaloosa discovery (Eni s interest 100%) was approved. The discovery is planned to be developed in synergy with the Longhorn production facilities. Start-up is expected in 2010 with production peaking at 1.5 KBOE/d.

Offshore exploration activities yielded positive results in the following blocks: (i) Green Canyon 859 (Eni s interest 12.5%) with the oil and gas Heidelberg-1 discovery; and (ii) Keathley Canyon 919 (Eni s interest 25%) with the oil and gas Hadrian West discovery.
Eni holds interests in 173 exploration and development blocks in Alaska, with interests ranging from 10 to 100% and over half of these blocks, Eni is the operator.

The Oooguruk oil field (Eni s interest 30%), in the Beaufort Sea, was Eni s only producing asset in Alaska. In 2009, production amounted to 6 KBBL/d (2 KBBL/d net to Eni).

There are ongoing activities relating to the phased development plan of the Nikaitchuq field (Eni s interest 100%) which is located in the North Slope basins. The first oil is expected in 2011 with peaking production at 28 KBBL/d.

Venezuela. Eni has been present in Venezuela since 1998. In 2009, Eni s production averaged 8 KBBL/d.

Activity is concentrated in the Gulf of Venezuela and in the Gulfo de Paria.

Exploration and production 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).

The Corocoro (Eni s interest 26%) field is Eni s only producing asset in the country. A second development phase is expected to be designed based on the results achieved in the first development phase relating to the well production rate and field performance under water and gas injection. A production peak of 40 KBBL/d (10 net to Eni) is expected in 2012.

A large gas discovery was made in the Perla field, located in the Cardon IV block (Eni 50%) in the Gulf of Venezuela, yielding 21 mmCF/d (approximately 3.7 KBOE/d) during flow tests. The field has been estimated to contain significant amount of resources. The Perla 2 well has been successfully drilled. The appraisal activity is progressing. Management expects to rapidly commence development activities, targeting early production in 2013.

On January 26, 2010 Eni and the Venezuelan National Oil Company, PDVSA, signed an agreement for the joint development of the giant field Junin 5, located in the Orinoco oil belt. Production start-up is planned for 2013 at an initial level of 75 KBBL/d and a target of long term production plateau of 240 KBOE/d. Development will be conducted through an "Empresa Mixta" (Eni 40%, PDVSA 60%). At the time of the establishment of the "Empresa Mixta", Eni will pay a bonus of $300 million, and additional amount of $346 million will be paid upon the achievement of certain project milestones. Finally, Eni will present a project for the construction of a power plant in Guiria peninsula.

Eni also holds interest in the Blanquilla and Tortuga exploration blocks in the Caribbean Sea, both with a 20% interest over an area of approximately 5,000 square kilometers.

Eni is participating with 19.5% interest in the Gulfo de Paria Centrale offshore exploration block, covering an area of 259 square kilometers, where the Punta Sur oil discovery is located.

Australia and Oceania

Eni s operations in Australia and Oceania area are conducted mainly in Australia. In 2009, Australia and Oceania area accounted for 1% of Eni s total worldwide production of oil and natural gas.

Australia. Eni has been present in Australia since 2000. In 2009 Eni s production of oil and natural gas averaged 16 KBOE/d. Activities are focused on conventional and deep offshore fields.

The main production blocks in which Eni holds interests are WA-33-L (Eni s interest 100%), WA-25-L (Eni operator with a 65% interest) and JPDA 03-13 (Eni s interest 10.99%). In the exploration phase Eni holds interests in 13 licenses (in 8 as operator and in 4 of which with a 100% interest), of particular interest are the Alberts blocks (WA-362/363/386/387-P) and JPDA 06-15 (Eni s interest 40%), where the Kitan discovery is located. The Kitan development activities started in April 2010.

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

In 2009, production start-up was achieved at the Blacktip gas field (Eni s interest 100%) located in the north western offshore in the South Bonaparte basin by means of a production platform linked to an onshore treatment plant with a capacity of 42 BCF/y. Natural gas produced from this field is sold under a 25-year contract signed with Power & Water Utility Co to fuel a power plant. In 2010 a production of 71 mmCF/d is expected.

Ongoing further development phase (phase 2) of the Bayu Undan field (Eni s interest 10.99%) is underway aimed at increasing liquids production and maintaining the field s production profile.

In the medium-term, management expects to increase Eni s production in Australia through ongoing development activities.

Capital Expenditures

See "Item 5 Liquidity and Capital Resources Capital Expenditures by Segment".

Gas & Power

Eni s Gas & Power segment engages in supply, transport, distribution, storage, re-gasification and marketing of natural gas, electricity and LNG. This segment also includes the activity of power generation that is ancillary to the marketing of electricity.

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In the context of a changed demand outlook and stronger competitive pressures both on the European and Italian markets, Eni s strategy in its Gas & Power segment aims at: (i) increasing international sales with the support of the integration of Distrigas; (ii) maintaining market share and profitability of Italian gas marketing operations; and (iii) increasing operational efficiency and effectiveness in the marketing, in the regulated businesses (i.e. Italian transport, distribution and storage activities) and power generations activities.

In 2009, the market environment was extremely difficult and the outlook for 2010 remains uncertain. Demand is slowly recovering from the huge contraction registred in 2009 as a severe economic downturn caused lower consumption, in particular in the power generation and industrial sectors. Assuming normal seasonal effects, European gas demand in 2009 declined by 7.4% from 2008 and the Italian market contracted by approximately 9 BCM from 2008, down 10%, and almost 10 BCM from the pre-crisis levels of 2007, down 12%.

In a period of lower demand, new gas supplies entered the market as several operators, including Eni, completed plans to upgrade gas import pipelines from gas producing countries or to build new facilities to import gas to Europe. In particular, Eni finalized plans to upgrade the import capacity of its two main pipelines from Russia and Algeria (the gas pipelines TAG and TTPC) by 13 BCM/y with new capacity entirely sold to third parties. A new LNG terminal with a capacity of 8 BCM/y commenced operations late in 2009, operated by a consortium of competitors. A situation of oversupply emerged from those trends. This situation was exacerbated by increased availability of LNG on the marketplace as the main market for LNG, the U.S., reduced its dependence on LNG imports due to greater production of gas from non-conventional sources. Large gas availability at the European hubs drove down spot prices which fell below the level of gas prices based on oil-linked formulas. Considering that a number of projects have been announced or sanctioned by Eni s competitors in order to further expand gas import capacity to Europe, management believes that the situation of oversupply will persist for some time which will continue to resulting in price and margin pressures.

Additionally, ongoing patterns towards energy preservation and rising competition from renewable or alternative sources of energy will further dampen recovery perspectives of gas demand. Specifically, at the March 2007 European Council, the European Heads of Government decided to adopt the Climate Action and Renewable Energy Package. This legislation was voted on by the European Parliament in December 2008. The package includes a commitment to reduce greenhouse gas (GHG) emissions by 20% by 2020 from emission levels recorded in 1990 (the target being 30% if an international agreement is reached), as well as a 20% improvement in energy efficiency within the EU Member States by 2020 and a 20% increase in renewable energy by 2020.

The combined impact of all these trends will weigh on the perspectives of a rapid demand recovery. Based on current assumptions and its ongoing perception of market trends, management expects that the gas market will recover the consumption levels of 2008 by 2013. Beyond 2013, management forecasts that demand will resume growing as gas is the cleanest fossil fuel due to its higher environmental compatibility as compared to other fossil fuels, widespread use of gas in power generation and economic and demographic development.

In consideration of a changed demand outlook, management has decreased its long-term projections of European gas demand growth from a previous compound average growth rate (c.a.g.r.) of 2% until 2020 to a revised 1.5% c.a.g.r. These assumptions imply an overall consumption level of approximately 600 BCM by 2020 compared to a previous forecast of 720 BCM. Management also expects the Italian market to grow less than anticipated at an annual rate that will be slightly lower than 2%, implying a level of consumption amounting to 94 BCM versus a previous forecast of 107 BCM by 2020. Considering that the European internal production of natural gas is declining, Europe will be increasingly dependent on gas imports. In such a scenario, Eni s long-term supply contracts and access to transport infrastructures will a remain competitive advantage.

For more detailed information about this topic and risks associated with those obligations, see "Item 3 Risk Factors", "Item 5 Contractual Obligations" and "Item 5 Management expectations".

In spite of an unfavorable trading environment and weak demand outlook, management intends to drive sales growth and support marketing margins. Planned actions are targeted to expand sales volumes and revenues in the European markets where the Company s presence is well established and market opportunities are being created. Those markets will include France, Germany, the Benelux countries and continental hubs in North Europe. Management plans to achieve sales volumes in Europe (excluding Italy) of approximately 59 BCM by 2013, with an annual growth rate of 6% from 2009 when sales in European markets amounted to 47 BCM (this amount comprises 44.97 BCM of sales of the Gas & Power segment and approximately 2 BCM of the Exploration & Production segment). The drivers of this growth are expected to be the integration of Distrigas activities, Eni s competitive advantages ensured by gas availability under long-term supply contracts and equity gas, also including benefits associated with contract re-negotiations, access to infrastructures, long-term relationships with key producing countries (mainly Russia, Algeria and Libya), market knowledge, a widespread commercial sale force and a diversified portfolio of clients.

In Italy, management intends to preserve profitability against the backdrop of a weak demand outlook and increased competition by leveraging on a number of marketing initiatives designed to enhance the Company s gas offer, by: (i) diversifying the offer in terms of combinations of pricing and services designed to better suit different customers needs; (ii) implementing a market approach tailored on local conditions; (iii) increasing capillarity through wide sale-force presence; and (iv) developing the combined offer of gas and power (dual offer) to drive sales to both business and retail customers.

Overall, Eni plans to increase worldwide gas sales targeting a volume of 118 BCM by 2013 with an average annual growth rate higher than 3% in the 2010-2013 period.

The achievement of sales and margin targets in both European markets and the Italian market will be supported by the impact of recent renegotiations of the Company s long-term supply contracts with producers. The Company also expects that renegotiations will enable it to gain more operational flexibility in fulfilling contractual obligations with respect to off-taking minimum annual quantities. See discussion on the Company s take-or-pay contracts below.

Management plans to strongly focus on cost control as a way to improve marketing margins. The action on costs will include a planned reduction in the cost to serve residential clients and optimizing operating and maintenance costs in power generation.

In the regulated businesses in Italy, management plans to deliver steady profitability as new investments will come on line benefiting from guaranteed returns from the Italian Authority for Electricity and Gas, as well as operating synergies deriving from the integration of all regulated Italian businesses in a single entity.

Over the medium term management intends to sustain the Company s actions by a disciplined capital expenditure plan focused in particular on the regulated businesses in Italy. Specifically, in the next four-year period Eni plans to invest approximately euro 8.3 billion in the Gas & Power segment of which euro 6.4 billion will mainly be devoted to: (i) expanding and upgrading transport networks in order to match the requirements of additional flexibility and security of the system. More than 80% of the total transport capital expenditures will continue to receive a 2% or 3% premium on the base allowed return; (ii) upgrading storage regulated capacity, both through the development of new fields and the expansion of existing capacity; and (iii) upgrading and developing local distribution networks. In addition, management plans to invest the remaining euro 1.8 billion capital expenditures in marketing activities by completing power plant upgrading and increasing generation flexibility (euro 0.7 billion), as well as in international marketing activities (euro 1.1 billion), including a storage project in the Hewett area off the British coast, to sustain growth in European markets.

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.

Supply of natural gas

In 2009, Eni s consolidated subsidiaries supplied 88.65 BCM of natural gas, a decrease of 1 BCM, or 1.1%, from 2008, due to declining gas demand whose impact was partly offset by the full consolidation of Distrigas.

Gas volumes supplied outside Italy (81.79 BCM from consolidated companies), imported in Italy or sold outside Italy, represented 91% of total supplies, an increase of 0.14 BCM, or 0.2%, from 2008, mainly due to the full contribution of Distrigas, whose main sources of supplies are long-term contracts with Norway, the Netherlands and Qatar via LNG, as well as spot markets in Western Europe. As a result, in 2009 higher volumes were purchased from: (i) Norway (up 5.68 BCM); (ii) Qatar (up 2.20 BCM); and (iii) the Netherlands (up 1.90 BCM).

Due to market trends, in particular a weak demand environment in Italy, the Gas & Power segment reduced its gas purchases from: (i) Algeria (down 5.40 BCM) which was also impacted by damage incurred to the TMPC pipeline in late December 2008; (ii) Libya (down 0.73 BCM); and (iii) Russia, where the Company reduced its off-takes by 2.75 BCM directed mainly to Italy. In addition, the reduction reflected the implementation of agreements with Gazprom which provided their entrance into the supplies market to Italian importers whereby Eni agreed to reduce its off-takes. This line item also includes volumes purchased to be resold on the Hungarian market.

Supplies in Italy (6.86 BCM) declined by 1.14 BCM from 2008, or 14.3%, due to lower domestic production.

In 2009, main gas volumes from equity production derived from: (i) Italian gas fields (6.5 BCM); (ii) the Wafa and Bahr Essalam fields in Libya linked to Italy through the GreenStream pipeline. In 2009 these two fields supplied 2.5 BCM net to Eni; (iii) certain Eni fields located in the British and Norwegian sections of the North Sea (2.9

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BCM); and (iv) other European areas (in particular Croatia with 0.8 BCM). Considering also the direct sales of the Exploration & Production division in Europe and in the Gulf of Mexico and LNG supplied from the Bonny liquefaction plant in Nigeria, supplied gas volumes from equity production were approximately 20.7 BCM representing 20% of total volumes available for sale.

In 2009, volumes from storage deposits owned by Eni s subsidiary Stoccaggi Gas Italia increased to 1.25 BCM compared to net input of natural gas volumes of 0.08 BCM in 2008.

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

Natural gas supply	**2007**	**2008**	**2009**
		(BCM)	
Italy	**8.65**	**8.00**	**6.86**
Outside Italy	**75.15**	**81.65**	**81.79**
Russia	*23.44*	*22.91*	*22.02*
Algeria (including LNG)	*18.41*	*19.22*	*13.82*
Libya	*9.24*	*9.87*	*9.14*
the Netherlands	*7.74*	*9.83*	*11.73*
Norway	*5.78*	*6.97*	*12.65*
the United Kingdom	*3.15*	*3.12*	*3.06*
Hungary	*2.87*	*2.84*	*0.63*
Qatar (LNG)	*-*	*0.71*	*2.91*
Other supplies of natural gas	*2.20*	*4.07*	*4.49*
Other supplies of LNG	*2.32*	*2.11*	*1.34*
Total supplies of subsidiaries	**83.80**	**89.65**	**88.65**
Withdrawals from (input to) storage	1.49	(0.08)	1.25
Network losses, measurement differences and other changes	(0.46)	(0.25)	(0.30)
Volumes available for sale of Eni s subsidiaries	**84.83**	**89.32**	**89.60**
Volumes available for sale of Eni s affiliates	**8.74**	**8.91**	**7.95**
E&P volumes	**5.39**	**6.00**	**6.17**
Total volumes available for sale	**98.96**	**104.23**	**103.72**

In order to secure long-term access to gas availability, in particular in view of supplying the Italian gas market, the Company has signed a number of long-term gas supply contracts with the key producing countries that supply the European gas markets. These contracts will ensure approximately 62.4 BCM of gas availability in 2010 (excluding the contribution of other subsidiaries and associates) with a residual life of approximately 20 years, and provide take-or-pay clauses whereby the Company is required to collect minimum predetermined volumes of gas in each year of the contractual term or, in case of failure, to pay the whole price, or a fraction of it, of 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. Amounts of cash pre-payments and time schedules for collecting pre-paid gas vary from contract to contract. Generally speaking, cash pre-payments are calculated on the basis of the energy prices current in the year of non-fulfillment with the balance due in the year when the gas is actually collected. Amounts of pre-payments range from 10 to 100 percent of the full price. The right to collect pre-paid gas expires within a ten-year term in some contracts or remains in place until contract expiration in other arrangements. In addition, rights to collect pre-paid gas in future years can be exercised provided that the Company has fulfilled its minimum take obligation in a given year and within the limit of the maximum annual quantity that can be collected in each contractual year. 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 in place in the year of the off-take. Similar considerations apply to ship-or-pay contractual obligations.

Management believes that the current outlook for gas demand and large gas availability on the marketplace, as well as the possible evolution of sector-specific regulation, represent risks factors to the Company s ability to fulfill its minimum take obligations associated with its long-term supply contracts. In 2009, Eni collected lower volumes than its minimum take due to an unfavorable demand environment. As a result, the Company deferred the relevant purchase costs to future periods by recognizing a non-current asset in the consolidated balance sheet. The non-current asset was recorded against a trade payable for an amount of euro 255 million based on the contractual purchase price formula provided in the relevant contractual arrangements and the contractual percentage of advance, as aligned to their net realizable value as of year end. The Company expects to collect the underlying gas volumes over a period longer than the next twelve months.

Management believes that over the next two years the Company will experience failure in fulfilling its take-or-pay obligations associated with significant volumes of gas, unless demand fundamentals improve substantially and a

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better balance between demand and supply is achieved in the marketplace. Currently, the Company is unable to forecast the timing of such a recovery.

However, based on management s projections for sales volumes and prices for the four-year plan and subsequent years, volumes for which an obligation to pay cash advances might arise due to take or pay clauses, will be off-taken within contractual terms, thus recovering cash advances.