ENI SPA
Form 20-F
April 06, 2018
TABLE OF CONTENTS

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, 2017

OR

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

OR

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

Commission file number: 1-14090

Eni SpA
(Exact name of Registrant as specified in its charter)
Republic of Italy
(Jurisdiction of incorporation or organization)
1, piazzale Enrico Mattei - 00144 Roma - Italy
(Address of principal executive offices)
Massimo Mondazzi
Eni SpA
1, piazza Ezio Vanoni
20097 San Donato Milanese (Milano) - Italy
Tel +39 02 52041730 - Fax +39 02 52041765
(Name, Telephone, Email and/or Facsimile number and Address of Company Contact Person)

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

Title of each class	Name of each exchange on which registered

Shares	New York Stock Exchange*
American Depositary Shares	New York Stock Exchange
(Which represent the right to receive two Shares)	* 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 shares3,634,185,330
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes No
If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.
Yes No
Note - Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes No
Indicate by check mark whether the registrant has submitted electronically and posted on their corporate Web sites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes No
Indicate by check mark whether 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 Emerging growth company
If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act.
† The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.
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

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

Certain disclosures contained herein including, without limitation, information appearing in "Item 4 – Information on the Company", and in particular "Item 4 – Exploration & Production", "Item 5 – Operating and Financial Review and Prospects" and "Item 11 – Quantitative and Qualitative Disclosures about Market Risk" contain forward-looking statements regarding future events and the future results of Eni that are based on current expectations, estimates, forecasts, and projections about the industries in which Eni operates and the beliefs and assumptions of the management of Eni. Eni may also make forward-looking statements in other written materials, including other documents filed with or furnished to the U.S. Securities and Exchange Commission (the "SEC"). In addition, Eni's senior management may make forward-looking statements orally to analysts, investors, representatives of the media and others. In particular, among other statements, certain statements with regard to management objectives, trends in results of operations, margins, costs, return on capital, risk management and competition are forward looking in nature. Words such as 'expects', 'anticipates', 'targets', 'goals', 'projects', 'intends', 'plans', 'believes', 'seeks', 'estimates', variations of such words, and simil 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 International Financial Standards (IFRS) as 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", "$", "U.S. dollars", "US$" and "USD" are to the currency of the United States, and references to "euro", "EUR" 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 any of the following Eni's business activities: Exploration & Production, Gas & Power, Refining & Marketing and Chemicals, Corporate and Other activities.

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

STATEMENTS REGARDING COMPETITIVE POSITION

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

TABLE OF CONTENTS

GLOSSARY

A glossary of oil and gas terms is available on Eni's web page at the address eni.com. Below is a selection of the most frequently used terms. Any reference herein to a non-GAAP measure and to its most directly comparable GAAP measure shall be intended as a reference to a non-IFRS measure and the comparable IFRS measure.

Financial terms	
Leverage	A non-GAAP measure of the Company's financial condition, calculated as the ratio between net borrowings and shareholders' equity, including non-controlling interest. For a discussion of management's view of the usefulness of this measure and its reconciliation with the most directly comparable GAAP measure, "Ratio of total debt to total shareholders's equity (including non-controlling interest)" 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, "Total debt" see "Item 5 – Financial condition".
TSR (Total Shareholder Return)	Management uses this measure to asses the total return on Eni's shares. It is calculated on a yearly basis, keeping account of the change in market price of Eni's shares (at the beginning and at end of year) and dividends distributed and reinvested at the ex-dividend date.
Business terms	
ARERA (Italian Regulatory Authority for Energy, Networks and Environment) formerly AEEGSI (Authority for Electricity Gas and Water)	The Italian Regulatory Authority for Energy, Networks and Environment is the Italian independent body which regulates, controls and monitors the electricity, gas and water 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. Furthermore, since December 2017 the Authority has also regulatory and control functions over the waste cycle, including sorted, urban and related waste.
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 right on exploration, development and production activities and for this reason it acquires a right

	to hydrocarbons extracted against the payment of royalties on production and taxes on oil revenues to the state.
Condensates	Condensates is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.
Consob	The Italian National Commission for listed companies and the stock exchange.

TABLE OF CONTENTS

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.
Conversion index	Ratio of capacity of conversion facilities to primary distillation capacity. The higher the ratio, the higher is the capacity of a refinery to obtain high value products from the heavy residue of primary distillation.
Deep waters	Waters deeper than 200 meters.
Development	Drilling and other post-exploration activities aimed at the production of oil and gas.
Enhanced recovery	Techniques used to increase or stretch over time the production of wells.
EPC	Engineering, Procurement and Construction.
EPCI	Engineering, Procurement, Construction and Installation.
Exploration	Oil and natural gas exploration that includes land surveys, geological and geophysical studies, seismic data gathering and analysis and well drilling.
FPSO	Floating Production Storage and Offloading System.
FSO	Floating Storage and Offloading System.
Infilling wells	Infilling wells are wells drilled in a producing area in order to improve the recovery of hydrocarbons from the field and to maintain and/or increase production levels.
LNG	Liquefied Natural Gas obtained through the cooling of natural gas to minus 160 °C at normal pressure. The gas is liquefied to allow transportation from the place of extraction to the sites at which it is transformed back into its natural gaseous state and consumed. One tonne of LNG corresponds to 1,400 cubic meters of gas.
LPG	Liquefied Petroleum Gas, a mix of light petroleum fractions, gaseous at normal pressure and easily liquefied at room temperature through limited compression.
Margin	The difference between the average selling price and direct acquisition cost of a finished product or raw material excluding other production costs (e.g. refining margin, margin on distribution of natural gas and petroleum products or margin of petrochemical products). Margin trends reflect the trading environment and are, to a certain extent, a gauge of industry profitability.
Mineral Potential	(Potentially recoverable hydrocarbon volumes) Estimated recoverable volumes which cannot be defined as reserves due to a number of reasons, such as the temporary lack of viable markets, a possible commercial recovery dependent on the development of new technologies, or for their location in accumulations yet to be developed or where evaluation of known accumulations is still at an early stage.
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.
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.

TABLE OF CONTENTS

Primary balanced refining capacity	Maximum amount of feedstock that can be processed in a refinery to obtain finished products measured in BBL/d.
Production Sharing Agreement (PSA)	Contract in use in African, Middle Eastern, Far Eastern and Latin American countries, among others, regulating relationships between states and oil companies with regard to the exploration and production of hydrocarbons. The mineral right is awarded to the national oil company jointly with the foreign oil company that has an exclusive right to perform exploration, development and production activities and can enter into agreements with other local or international entities. In this type of contract the national oil company assigns to the international contractor the task of performing exploration and production with the contractor’s equipment and financial resources. Exploration risks are borne by the contractor and production is divided into two portions: “Cost Oil” is used to recover costs borne by the contractor and “Profit Oil” is divided between the contractor and the national company according to variable schemes and represents the profit deriving from exploration and production. Further terms and conditions of these contracts may vary from country to country.
Proved reserves	Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. Reserves are classified as either developed and undeveloped. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.
Reserves	Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.
Reserve life index	Ratio between the amount of proved reserves at the end of the year and total production for the year.
Reserve replacement ratio	Measure of the reserves produced replaced by proved reserves. Indicates the company’s ability to add new reserves through exploration and purchase of property. A rate higher than 100% indicates that more reserves were added than produced in the period. The ratio should be averaged on a three-year period in order to reduce the distortion deriving from the purchase of proved property,

the revision of previous estimates, enhanced recovery, improvement in recovery rates and changes in the amount of reserves – in PSAs – due to changes in international oil prices.

v

TABLE OF CONTENTS

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.
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.
Title Transfer Facility	The Title Transfer Facility, more commonly known as TTF, is a virtual trading point for natural gas in the Netherlands. TTF Price is quoted in euro per megawatt hour and, for business day, is quoted day-ahead, i.e. delivered next working day after assessment.
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.

TABLE OF CONTENTS

ABBREVIATIONS

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

CONVERSION TABLE

1 acre	= 0.405 hectares	
1 barrel	= 42 U.S. gallons	
1 BOE	= 1 barrel of crude oil	= 5,458 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 0.00647 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)

TABLE OF CONTENTS

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 as issued by the International Accounting Standards Board (IASB). The tables below present Eni selected historical financial data prepared in accordance with IFRS as of and for the years ended December 31, 2013, 2014, 2015, 2016 and 2017. In 2015, the business segment Engineering & Construction, operated by Eni's subsidiary Saipem, was classified as discontinued operations based on the guidelines of IFRS 5. Eni's interest in Saipem was divested on January 26, 2016; financial data for 2014 and 2013 have been restated accordingly.

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,				
	2017	2016	2015	2014	2013
	(€ million except data per share and per ADR)				
CONSOLIDATED PROFIT STATEMENT DATA					
Net sales from continuing operations	66,919	55,762	72,286	98,218	104,117
Operating profit (loss) by segment from continuing operations					
Exploration & Production	7,651	2,567	(959)	10,727	15,349
Gas & Power	75	(391)	(1,258)	64	(2,923)
Refining & Marketing and Chemicals	981	723	(1,567)	(2,811)	(2,261)
Corporate and Other activities	(668)	(681)	(497)	(518)	(736)
Impact of unrealized intragroup profit elimination and other consolidation adjustments(1)	(27)	(61)	1,205	1,503	928
Operating profit (loss) from continuing operations	8,012	2,157	(3,076)	8,965	10,357
Net profit (loss) attributable to Eni from continuing operations	3,374	(1,051)	(7,952)	1,720	5,808
Net profit (loss) attributable to Eni from discontinued operations	0	(413)	(826)	(417)	(488)
Net profit (loss) attributable to Eni	3,374	(1,464)	(8,778)	1,303	5,320
Data per ordinary share (euro)(2)					
Operating profit (loss):					
– basic	2.22	0.60	(0.85)	2.48	2.86
– diluted	2.22	0.60	(0.85)	2.48	2.86
Net profit (loss) attributable to Eni basic and diluted from continuing operations	0.94	(0.29)	(2.21)	0.48	1.60
Net profit (loss) attributable to Eni basic and diluted from discontinued operations	0.00	(0.12)	(0.23)	(0.12)	(0.13)
Net profit (loss) attributable to Eni basic and diluted	0.94	(0.41)	(2.44)	0.36	1.47

Data per ADR ($)(2)(3)					
Operating profit (loss):					
– basic	5.03	1.33	(1.90)	6.59	7.59
– diluted	5.03	1.33	(1.90)	6.59	7.59
Net profit (loss) attributable to Eni basic and diluted from continuing operations	2.12	(0.65)	(4.90)	1.27	4.26
Net profit (loss) attributable to Eni basic and diluted from discontinued operations	0.00	(0.25)	(0.51)	(0.31)	(0.36)
Net profit (loss) attributable to Eni basic and diluted	2.12	(0.90)	(5.41)	0.96	3.90

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

(2)
Euro per share or U.S. dollars per American Depositary Receipt (ADR), as the case may be. One ADR represents two Eni shares. The dividend amount for 2017 is based on the proposal of Eni’s management which is submitted for approval at the Annual General Shareholders’ Meeting scheduled on May 10, 2018.

(3)
Eni’s financial statements are reported 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 2013 through 2016 were translated into U.S. dollars for each year presented using the Noon Buying Rate on payment dates, as recorded on the payment date of the interim dividend and of the balance to the full-year dividend, respectively. The dividend for 2017 based on the management’s proposal to the General Shareholders’ Meeting and subject to approval was translated as per the portion related to the interim dividend (€0.80 per ADR) at the Noon Buying Rate recorded on the payment date on September 20, 2017, while the balance of €0.80 per ADR was translated at the Noon Buying Rate as recorded on December 31, 2017. The balance dividend for 2017 once the full-year dividend is approved by the Annual General Shareholders’ Meeting is payable on May 23, 2018 to holders of Eni shares, being the ex-dividend date May 21, 2018 while ADRs holders will be paid on June 7, 2018.

TABLE OF CONTENTS

	As of December 31,				
	2017	2016	2015	2014	2013
	(€ million except data per share and per ADR)				
CONSOLIDATED BALANCE SHEET DATA					
Total assets	114,928	124,545	139,001	150,366	142,426
Short-term and long-term debt	24,707	27,239	27,793	25,891	25,560
Capital stock issued	4,005	4,005	4,005	4,005	4,005
Non-controlling interest	49	49	1,916	2,455	2,842
Shareholders' equity – Eni share	48,030	53,037	55,493	63,186	61,211
Capital expenditures from continuing operations	8,681	9,180	10,741	11,178	11,221
Weighted average number of ordinary shares outstanding (fully diluted – shares million)	3,601	3,601	3,601	3,610	3,623
Dividend per share (euro)(1)	0.80	0.80	0.80	1.12	1.10
Dividend per ADR ($)(1)(2)	1.81	1.77	1.77	2.65	2.99

(1)
Euro per share or U.S. dollars per American Depositary Receipt (ADR), as the case may be. One ADR represents two Eni shares. The dividend amount for 2017 is based on the proposal of Eni's management which is submitted for approval at the Annual General Shareholders' Meeting scheduled on May 10, 2018.

(2)
Eni's financial statements are reported 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 2013 through 2016 were translated into U.S. dollars for each year presented using the Noon Buying Rate on payment dates, as recorded on the payment date of the interim dividend and of the balance to the full-year dividend, respectively. The dividend for 2017 based on the management's proposal to the General Shareholders' Meeting and subject to approval was translated as per the portion related to the interim dividend (€0.80 per ADR) at the Noon Buying Rate recorded on the payment date on September 20, 2017, while the balance of €0.80 per ADR was translated at the Noon Buying Rate as recorded on December 31, 2017. The balance dividend for 2017 once the full-year dividend has been approved by the Annual General Shareholders' Meeting is payable on May 23, 2018 to holders of Eni shares, being the ex-dividend date May 21, 2018 while ADRs holders will be paid on June 7, 2018.

TABLE OF CONTENTS

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, 2013, 2014, 2015, 2016 and 2017.

	Year ended December 31,				
	2017	2016	2015	2014	2013
Proved reserves of liquids of consolidated subsidiaries at period end (mmBBL)	3,262	3,230	3,372	3,077	3,079
of which developed	2,220	2,190	2,100	1,847	1,831
Proved reserves of liquids of equity-accounted entities at period end (mmBBL)	160	168	187	149	148
of which developed	43	43	48	46	35
Proved reserves of natural gas of consolidated subsidiaries at period end (BCF)	17,290	18,462	14,302	14,808	14,442
of which developed	9,535	9,244	8,899	8,342	8,542
Proved reserves of natural gas of equity-accounted entities at period end (BCF)	2,182	3,871	3,993	3,737	3,726
of which developed	1,916	1,905	1,402	120	34
Proved reserves of hydrocarbons of consolidated subsidiaries in mmBOE at period end	6,430	6,613	5,975	5,772	5,708
of which developed	3,967	3,884	3,720	3,366	3,387
Proved reserves of hydrocarbons of equity-accounted entities in mmBOE at period end	560	877	915	830	827
of which developed	394	391	303	67	40
Average daily production of liquids (KBBL/d)(1)	852	878	908	828	833
Average daily production of natural gas available for sale (mmCF/d)(1)	4,734	4,329	4,284	3,782	3,868
Average daily production of hydrocarbons available for sale (KBOE/d)(1)	1,719	1,671	1,688	1,517	1,537
Hydrocarbon production sold (mmBOE)	622.3	608.6	614.1	549.5	555.3
Oil and gas production costs per BOE(2)	8.45	7.79	9.18	12.00	12.19
Profit per barrel of oil equivalent(3)	8.72	1.98	(3.83)	9.86	16.19

(1)
Referred to Eni's subsidiaries and its equity-accounted entities. Natural gas production volumes exclude gas consumed in operations (451, 442, 397, 478 and 527 mmCF/d in 2013, 2014, 2015, 2016 and 2017 respectively).

(2)
Expressed in U.S. dollars. Consists of production costs of consolidated subsidiaries (costs incurred to operate and maintain wells and field equipment including also royalties) prepared in accordance with IFRS divided by production on an available-for-sale basis, expressed in barrels of oil equivalent. See the unaudited supplemental oil and gas information in "Item 18 – Notes to the Consolidated Financial Statements".

(3)
Expressed in U.S. dollars. Results of operations from oil and gas producing activities of consolidated subsidiaries, divided by actual sold production, in each case prepared in accordance with IFRS to meet ongoing U.S. reporting obligations under Topic 932. See the unaudited supplemental oil and gas information in "Item 18 – Notes to the Consolidated Financial Statements" for a calculation of results of operations from oil and gas producing activities.

TABLE OF CONTENTS

Selected Operating Information continued

	Year ended December 31,				
	2017	2016	2015	2014	2013
Sales of natural gas to third parties(1)	71.34	77.24	79.06	76.11	77.67
Natural gas consumed by Eni(1)	6.18	6.10	5.88	5.62	5.93
Sales of natural gas of affiliates (Eni's share)(1)	3.31	2.97	2.78	4.38	6.96
Worldwide natural gas sales(1)	80.83	86.31	87.72	86.11	90.56
Electricity sold(2)	35.33	37.05	34.88	33.58	35.05
Refinery throughputs(3)	24.02	24.52	26.41	25.03	27.38
Balanced capacity of wholly-owned refineries(4)	388	388	388	404	574
Retail sales (in Italy and rest of Europe)(3)	8.54	8.59	8.89	9.21	9.69
Number of service stations at period end (in Italy and rest of Europe)	5,544	5,622	5,846	6,220	6,386
Chemical production(3)	5.82	5.65	5.70	5.28	5.82
Average throughput per service station (in Italy and rest of Europe)(5)	1,783	1,742	1,754	1,725	1,828
Employees at period end (number)	32,934	33,536	34,196	34,846	36,678

(1)
Expressed in BCM.

(2)
Expressed in TWh.

(3)
Expressed in mmtonnes.

(4)
Expressed in KBBL/d.

(5)
Expressed in thousand liters per day.

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 €)			
Year ended December 31,				
2013	1.38	1.28	1.33	1.38
2014	1.39	1.21	1.33	1.21
2015	1.20	1.05	1.11	1.09

2016	1.15	1.04	1.10	1.06
2017	1.20	1.04	1.13	1.20

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

TABLE OF CONTENTS

	High	Low	At period end
	(U.S. dollars per €)		
October 2017	1.18	1.16	1.16
November 2017	1.19	1.16	1.19
December 2017	1.20	1.17	1.20
January 2018	1.25	1.19	1.24
February 2018	1.25	1.22	1.22
March 2018	1.24	1.22	1.23

Fluctuations in the exchange rate between the euro and the dollar affect the dollar equivalent of the euro price of the Shares on the electronic stock exchange 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 March 30, 2018 was $1.232 per €1.00.

Risk factors

The risks described below may have a material effect on our operational and financial performance. We invite our investors to consider these risks carefully.

Eni's operating results, cash flow and rates of growth are affected by volatile prices of crude oil, natural gas, oil products and chemicals

Prices of oil and natural gas have a history of volatility due to many factors that are beyond Eni's control. These factors include among other things:

- global and regional dynamics of oil and gas supply and demand and global level of inventories. In 2017 crude oil prices were volatile, with the first half of the year characterized by market uncertainties about a rebalancing between global demand and supplies and the overhang of high global inventories. From the second part of the year, the recovery in crude oil prices progressively gained steam with prices reaching levels unseen in recent years, at around 70 $/BBL in early 2018. This upward trend was driven by better market fundamentals and full effectiveness of production cuts agreed by OPEC Countries at the end of November 2016 to reduce the output of the cartel, joined also by certain non-OPEC countries (among which Russia). The average price for the Brent crude oil benchmark increased by 24% y-o-y at about 54 $/BBL;
- global political developments, including sanctions imposed on certain producing countries and conflict situations;
- global economic and financial market conditions;
- the ability of the OPEC cartel to control world supply and therefore oil prices;
- prices and availability of alternative sources of energy (e.g., nuclear, coal and renewables);
- weather conditions;
-

operational issues;

- governmental regulations and actions;

- success in the development and deployment of new technologies for the recovery of crude oil and natural gas reserves and technological advances affecting energy consumption;

- competition from alternative energy sources like solar energy, photovoltaic and other renewables; and

- growing sensibility among the public and the commitment of the world nations to addressing the issue of global warming and climate change by reducing the release in the atmosphere of greenhouse gases (“GHG”) produced by the consumption of hydrocarbons in human activities.

All these factors can affect the global balance between demand and supply for oil and prices of crude oil, natural gas, and other energy commodities.

TABLE OF CONTENTS

Management believes that current market dynamics are supportive of the ongoing recovery in crude oil prices. Going forward, we foresee a better balance between demand and supply driven by an improving macroeconomic outlook and the effects of the reduced investments made by international oil companies during the downturn. The production cuts agreed by OPEC with the cooperation of other countries (principally Russia) will provide further support in the short term. However, management has also evaluated the continuing risks and uncertainties inherent in such forecasts, including actual implementation of the production cuts announced by the OPEC, structural changes that have been affecting the oil industry – e.g. the increase in oil supply following the U.S. tight oil revolution – the unpredictable impact of geopolitical crisis and the greater role played by renewable energy sources, as well as risks associated with internationally-agreed measures intended to reduce GHG. Based on this outlook, management basically confirmed its long-term assumption for the benchmark Brent price to 72 $/BBL in 2021 real terms (under the previous plan it was 71.4 $/BBL) in elaborating the Group's financial projections of the 2018 – 2021 industrial plan and the estimations of recoverability of the carrying amounts of the Group's oil and gas assets as of December 31, 2017.

Fluctuations in oil and natural gas prices have had and may in the future have a material effect on the Group's results of operations and cash flow. Lower prices from one year to another negatively affect the Group's consolidated results of operations and cash flow. This is because lower prices translate into lower revenues recognized in the Company's Exploration & Production segment at the time of the price change, whereas expenses in this segment are either fixed or less sensitive to changes in crude oil prices than revenues. Based on the current portfolio of oil and gas assets, Eni's management estimates that the Company's consolidated net profit would vary by approximately euro 200 million for each one dollar change in the price of the Brent crude oil benchmark with respect to the price case assumed in Eni's financial projections for 2018 at 60 $/BBL. Net cash provided by operating activities is expected to vary by a similar amount.

In addition to the adverse effect on revenues, profitability and cash flow, lower oil and gas prices could result in debooking of proved reserves, if they become uneconomic in this type of environment, and asset impairments. Depending on the significance and speed of a decrease in crude oil prices, Eni may also need to review investment decisions and the viability of development projects. The effect of lower oil and gas prices over prolonged periods on Eni's results of operations and cash flow may adversely affect the funds available to finance expansion projects, further reducing the Company's ability to grow future production and revenues. In addition, such lower price may reduce returns from development projects, either planned or in progress, forcing the Company to reschedule, postpone or cancel development projects.

In response to weakened oil and gas industry conditions and resulting revisions made to rating agency commodity price assumptions, lower commodity prices may also reduce the Group's access to capital and lead to a downgrade or other negative rating action with respect to the Group's credit rating by rating agencies, including Standard & Poor's Ratings Services ("S&P") and Moody's Investor Services Inc ("Moody's"). These downgrades may negatively affect the Group's cost of capital, increase the Group's financial expenses, and may limit the Group's ability to access capital markets and execute aspects of the Group's business plans.

Eni estimates that movements in oil prices impact pricing for approximately 50 per cent. of its current production. The remaining portion of Eni's current production is largely unaffected by crude oil price movements considering that the Company's property portfolio is characterized by a sizeable presence of production sharing contracts, whereby, due to the cost recovery mechanism, the Company is entitled to a larger number of barrels in the event of a fall in crude oil prices. (See the specific risks of the Exploration & Production segment in "Risks associated with the exploration and production of oil and natural gas" below).

The Group's results from its Refining & Marketing and Chemicals businesses are primarily dependent upon the supply and demand for refined and chemical products and the associated margins on refined product and chemical products sales, with the impact of changes in oil prices on results of these segments being dependent upon the speed at which the prices of products adjust to reflect movements in oil prices.

Because of the above mentioned risks, a prolonged decline in commodity prices would materially and adversely affect the Group's business prospects, financial condition, results of operations, cash flows, ability to finance planned capital expenditures and commitments and may impact shareholder returns, including dividends and the share price.

TABLE OF CONTENTS

Competition

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

Eni faces strong competition in each of its business segments.

The current competitive environment in which Eni operates is characterized by volatile prices and margins of energy commodities, limited product differentiation and complex relationships with state-owned companies and national agencies of the countries where hydrocarbons reserves are located to obtain mineral rights. As commodity prices are beyond the Company's control, Eni's ability to remain competitive and profitable in this environment requires continuous focus on technological innovation, the achievement of efficiencies in operating cost and efficient management of capital resources. It also depends on Eni's ability to gain access to new investment opportunities, both in Europe and worldwide.

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

- Throughout 2016, the Gas & Power segment experienced a history of operating losses due to a difficult market environment in the European gas sector. Eni is facing strong competition from gas and energy players to sell gas to the industrial segment, the thermoelectric sector and the retail customers both in the Italian market and in markets across Europe. Competition has been driven by ongoing weak demand, oversupplies and use of alternative energy sources for the production of electricity (renewables or coal). The production of gas-fired electricity is one of the major outlet for gas. In recent years the use of gas in gas-fired power plants has been negatively affected by an increased use of coal in firing power plants due to cost advantages and a dramatic growth in the adoption of renewable sources of energy (photovoltaic, wind and solar). The large-scale development of shale gas in the United States has been another fundamental trend that aggravated the oversupply situation in Europe because many LNG projects worldwide that originally targeted the U.S. market, were redirected to an already saturated European market. Furthermore, many LNG terminals in the US are undergoing upgrading projects designed to convert them into gas liquefaction facilities with the aim of exporting the large gas surplus out of the US. This development will further increase global gas supplies. In recent years, large gas availability in Europe led to the development of liquid spot markets where gas is traded daily. Prices at these hubs have become the benchmark to selling prices and have been on a downtrend in recent years. These trends have negatively affected the profitability of our Gas & Power business, because the Company is part of long-term gas supply contracts with take-or-pay clauses, which exposed us to a volume risk, as we are contractually required to purchase minimum annual amounts of gas or, if we fail to do so, to pay the corresponding price. Additionally, we have booked the transportation rights along the main gas backbones across Europe to deliver our contracted gas volumes to end-markets. In a weak market, the need to dispose of the minimum off-take of gas have negatively affected our margins. Looking forward, we believe that the competitive landscape in our Gas & Power business will remain challenging due to expected weak growth in demand, also reflecting political uncertainty in the EU about the role of gas in the energy mix, the continuing build of oversupplies and inter-fuel competition. Eni believes that these ongoing negative trends may adversely affect the Company's future results of operations and cash flows.

- In its Gas & Power segment, Eni is vertically integrated in the production of electricity via its gas-fired power plants, which are currently utilizing the combined-cycle technology. In the electricity business, Eni competes with other producers and traders from Italy or outside Italy who sell electricity in the Italian market. The Company expects continuing competition due to the projections of moderate economic growth in Italy and Europe over the foreseeable future, also causing outside players to place excess production on the Italian market. The economics of the gas-fired electricity business have dramatically changed over the latest few years due to ongoing

TABLE OF CONTENTS

competitive trends. Spot prices of electricity in the wholesale market throughout Europe decreased due to excess supplies driven by the growing production of electricity from renewable sources, that also benefit from governmental subsidies, and a recovery in the production of coal-fired electricity which was helped by a substantial reduction in the price of this fuel on the back of a massive oversupply of coal occurring on a global scale. As a result of falling electricity prices, margins on the production of gas-fired electricity have been negatively affected. Eni believes that the competitive scenario in this business will remain challenging in the foreseeable future, negatively affecting results of operations and cash flow.

- In the Refining & Marketing segment, Eni faces strong competition in both industrial and commercial activities. European refining margins remain lower than other areas due to higher energy costs, weak trends in demand for fuels and competitive pressure from cheaper productions mainly coming from Middle East and Asia and tighter compliance constraints. We believe that the competitive environment will remain challenging in the foreseeable future, also considering refining overcapacity in the European area. In marketing, Eni faces competition from other oil companies and new participants such as un-branded operators and large retailers, that leverage on the price awareness of final consumers to increase their market share. All these operators compete with each other primarily in terms of pricing and, to a lesser extent, service quality.

- In the Chemical business, Eni faces strong competition from well-established international players and state-owned petrochemical companies, particularly in the most commoditized segments such as the production of basic petrochemical products and plastics. Many of those competitors based in the Far East and the Middle East are able to benefit from cost advantages due to scale, favourable environmental regulations, availability of cheap feedstock and proximity to end-markets. Excess capacity across Europe is also fuelling competition in this business. Furthermore, petrochemical producers based in the United States have regained market share, as their cost structure has become competitive due to the availability of cheap feedstock deriving from the production of domestic shale gas. Competition exacerbates the impact of any macroeconomic downturn on the business' results of operations and cash flow; additionally, the business results are exposed to fluctuation in the relative prices of oil-based feedstock and final prices of petrochemicals products. The Company expects continuing margin pressures in its petrochemical segment in the foreseeable future as a result of those trends.

Safety, security, environmental and other operational risks

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

In the Exploration & Production segment, Eni faces natural hazards and other operational risks including those relating to the physical characteristics of oil and natural gas fields. These include the risks of eruptions of crude oil or of natural gas, discovery of hydrocarbon pockets with abnormal pressure, crumbling of well openings, leaks that can harm the environment and the security of Eni's personnel and risks of blowout, fire or explosion. Accidents at a single well can lead to loss of life, damage or destruction to properties, environmental damage, GHG emissions and consequently potential economic losses that could have a material and adverse effect on the business, results of operations, liquidity, reputation and prospects of the Group, including its share price and dividends.

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

TABLE OF CONTENTS

All of Eni's segments of operations involve, to varying degrees, the transportation of hydrocarbons. Risks in transportation activities depend both on the hazardous nature of the products transported, and on the transportation methods used (mainly pipelines, shipping, river freight, rail, road and gas distribution networks), the volumes involved and the sensitivity of the regions through which the transport passes (quality of infrastructure, population density, environmental considerations). All modes of transportation of hydrocarbons are particularly susceptible to a loss of containment of hydrocarbons and other hazardous materials, and, given the high volumes involved, could present a significant risk to people and the environment.

The Company invests significant resources in order to upgrade the methods and systems for safeguarding safety and health of employees, contractors and communities, and the environment; to prevent risks; to comply with applicable laws and policies; and to respond to and learn from unforeseen incidents. Eni seeks to minimize these operational risks by carefully designing and building facilities, including wells, industrial complexes, plants and equipment, pipelines, storage sites and other facilities, and managing its operations in a safe and reliable manner and in compliance with all applicable rules and regulations. These measures may not ultimately adequately manage these risks. Failure to manage these risks could cause unforeseen incidents, including releases or oil spills, blowouts, fire, mechanical failures and other incidents resulting in personal injury, loss of life, environmental damage, legal liabilities and/or damage claims, destruction of crude oil or natural gas wells, as well as damage to equipment and other property, all of which could lead to a disruption in operations.

Eni's operations are often conducted in difficult and/or environmentally sensitive locations such as the Gulf of Mexico, the Caspian Sea and the Arctic. In such locations, the consequences of any incident could be greater than in other locations. Eni also faces risks once production is discontinued, because Eni's activities require the decommissioning of productive infrastructures and environmental sites remediation and clean-up. Furthermore, in certain situations where Eni is not the operator, the Company may have limited influence and control over third parties, which may limit its ability to manage and control such risks.

Eni retains worldwide third-party liability insurance coverage, which is designed to hedge part of the liabilities associated with damage to third parties, loss of value to the Group's assets related to unfavourable events and in connection with environmental clean-up and remediation. Particularly, Eni's entities are insured against liabilities for damage to third parties and environmental claims up to $1.2 billion in case of offshore incident and $1.4 billion in case of incident at onshore facilities (refineries). Additionally, the Company may also activate further insurance coverage in case of specific capital projects and other industrial initiatives. Management believes that its insurance coverage is in line with industry practice and is sufficient to cover normal risks in its operations. However, the Company is not insured against all potential risks. In the event of a major environmental disaster, such as the incident which occurred at the Macondo well in the Gulf of Mexico several years ago, for example, Eni's third-party liability insurance would not provide any material coverage and thus the Company's liability would far exceed the maximum coverage provided by its insurance. The loss Eni could suffer in the event of such a disaster would depend on all the facts and circumstances of the event and would be subject to a whole range of uncertainties, including legal uncertainty as to the scope of liability for consequential damages, which may include economic damage not directly connected to the disaster.

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

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

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

The exploration and production of oil and natural gas require high levels of capital expenditures and are subject to natural hazards and other uncertainties, including those relating to the physical characteristics of oil and gas fields. 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 leases, the imposition of specific drilling and other work obligations, income taxes and taxes on production, environmental protection measures, control over the development and abandonment of fields and installations, and restrictions on production. A description of the main risks facing the Company's business in the exploration and production of oil and gas is provided below.

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

Eni has material offshore operations relating to the exploration and production of hydrocarbons. In 2017, approximately 53% of Eni's total oil and gas production for the year derived from offshore fields, mainly in Libya, Norway, Angola, Egypt, the Gulf of Mexico, Italy, Congo, the United Kingdom and Nigeria. Offshore operations in the oil and gas industry are inherently riskier than onshore activities. Offshore accidents and spills could cause damage of catastrophic proportions to the ecosystem and health and security of people due to objective difficulties in handling hydrocarbons containment, pollution, poisoning of water and organisms, length and complexity of cleaning operations and other factors. Furthermore, offshore operations are subject to marine risks, including storms and other adverse weather conditions and vessel collisions, as well as interruptions or termination by governmental authorities based on safety, environmental and other considerations. Failure to manage these risks could result in injury or loss of life, damage to property or environmental damage, and could result in regulatory action, legal liability, loss of revenues and damage to Eni's reputation and could have a material adverse effect on Eni's operations, results, liquidity, reputation, business prospects and the share price.

Exploratory drilling efforts may be unsuccessful

Exploration drilling for oil and gas involves numerous risks including the risk of dry holes or failure to find commercial quantities of hydrocarbons. The costs of drilling, completing and operating wells have margins of uncertainty, and drilling operations may be unsuccessful because of a large variety of factors, including geological failure, unexpected drilling conditions, pressure or heterogeneities in formations, equipment failures, well control (blowouts) and other forms of accidents, and shortages or delays in the delivery of equipment. The Company also engages in exploration drilling activities offshore, including in deep and ultra-deep waters, in remote areas and in environmentally-sensitive locations (such as the Barents Sea). In these locations, the Company generally experiences more challenging conditions and incurs higher exploration costs than onshore or in shallow waters. Furthermore, deep and ultra-deep water operations require significant time before commercial production of discovered reserves can commence, increasing both the operational and financial risks associated with these activities. Because Eni plans to make investments in executing exploration projects, it is likely that the Company will incur significant amounts of dry hole expenses in future years. Unsuccessful exploration activities and failure to discover additional commercial reserves could reduce future production of oil and natural gas, which is highly dependent on the rate of success of exploration projects, and could have an adverse impact on Eni's future growth prospects, results of operations and liquidity.

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

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

- the outcome of negotiations with joint venture partners, governments and state-owned companies, suppliers, customers or others, including, for example, Eni's ability to negotiate favourable long-term contracts to market gas reserves;
- commercial arrangements for pipelines and related equipment to transport and market hydrocarbons;
- timely issuance of permits and licences by government agencies;

- the Company's relative size compared to its main competitors which may prevent it from participating in large-scale projects or affect its ability to reap benefits associated with economies of scale;

TABLE OF CONTENTS

- the ability to carefully carry out front-end engineering design in order to prevent the occurrence of technical inconvenience during the execution phase; timely manufacturing and delivery of critical equipment by contractors, shortages in the availability of such equipment or lack of shipping yards where complex offshore units such as FPSO and platforms are built; these events may cause cost overruns and delays impacting the time-to-market of the reserves;

- risks associated with the use of new technologies and the inability to develop advanced technologies to maximize the recoverability rate of hydrocarbons or gain access to previously inaccessible reservoirs;

- poor performance in project execution on the part of contractors who are awarded project construction activities generally based on the EPC (Engineering, Procurement and Construction) – turn key contractual scheme. Eni believes this kind of risk may be due to lack of contractual flexibility, poor quality of front-end engineering design and commissioning delays;

- changes in operating conditions and cost overruns. In recent years, the industry has been adversely impacted by the growing complexity and scale of projects which drove cost increases and delays, including higher environmental and safety costs;

- 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.

As previously described, events such as poor project execution, inadequate front-end engineering design, delays in the achievement of critical phases and project milestones, delays in the delivery of production facilities and other equipment by third parties, differences between scheduled and actual timing of the first oil, as well as cost overruns may adversely affect the economic returns of Eni's development projects. Failure to deliver major projects on time and on budget could negatively affect results of operations, cash flow and the achievement of short-term targets of production growth. Lastly, the development and marketing of hydrocarbon reserves typically require several years after a discovery is made. This is because a development project involves an array of complex and lengthy activities, including appraising a discovery in order to evaluate its technical and economic feasibility, sanctioning a development project and the building and commissioning of related facilities. As a consequence, rates of return for such long lead time projects are exposed to the volatility of oil and gas prices and costs which may be substantially different from those estimated when the investment decision was made, thereby leading to lower return rates. Moreover, projects executed with partners and joint venture partners reduce the ability of the Company to manage risks and costs, and Eni could have limited influence over and control of the operations and performance of its partners. Furthermore, Eni may not have full operational control of the joint ventures in which it participates and may have exposure to counterparty credit risk and disruption of operations and strategic objectives due to the nature of its relationships.

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

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

Unless the Company is able to replace produced oil and natural gas, its reserves will decline. In addition to being a function of production, revisions and new discoveries, the Company's reserve replacement is also affected by the entitlement mechanism in its production sharing agreements ("PSAs"). Pursuant to these 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 expenditure. For a discussion of the Group's sensitivity of production volumes to movements in crude oil prices see "Item 5- management expectations of operations. The opposite occurs in case of lower oil prices.

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, negotiations with national oil companies and other entities owners of known reserves and acquisitions.

An inability to replace produced reserves by discovering, acquiring and developing additional reserves could adversely impact future production levels and growth prospects. If Eni is unsuccessful in meeting its long-term targets of production growth and reserve replacement, Eni's future total proved reserves and production will decline and this will negatively affect future results of operations, cash flow and business prospects.

TABLE OF CONTENTS

Uncertainties in estimates of oil and natural gas reserves

The accuracy of proved reserve estimates and of projections of future rates of production and timing of development expenditures depends on a number of factors, assumptions and variables, including:

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

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

Many of the factors, assumptions and variables involved in estimating proved reserves are subject to change over time and therefore affect the estimates of oil and natural gas reserves.

Accordingly, the estimated reserves reported as of the end of 2017 could be significantly different from the quantities of oil and natural gas that will be ultimately recovered. Any downward revision in Eni's estimated quantities of proved reserves would indicate lower future production volumes, which could adversely impact Eni's results of operations and financial condition.

The development of the Group's proved undeveloped reserves may take longer and may require higher levels of capital expenditures than it currently anticipates. The Group's proved undeveloped reserves may not be ultimately developed or produced

At 31 December 2017, approximately 38% of the Group's total estimated proved reserves (by volume) were undeveloped and may not be ultimately developed or produced. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The Group's reserve estimates assume it can and will make these expenditures and conduct these operations successfully. These assumptions may not prove to be accurate. The Group's reserve report at 31 December 2017 includes estimates of total future development costs associated with the Group's proved undeveloped reserves of approximately euro 33.2 billion (undiscounted). It cannot be certain that estimated costs of the development of these reserves will prove correct, development will occur as scheduled, or the results of such development will be as estimated. In case of change in the Company's plans to develop of those reserves, or if it is not otherwise able to successfully develop these reserves as a result of the Group's inability to fund necessary capital expenditures or otherwise, it will be required to remove the associated volumes from the Group's reported proved reserves.

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

Oil and gas operations are subject to the payment of royalties and income taxes, which tend to be higher than those payable in many other commercial activities. Furthermore, in recent years, Eni has experienced adverse changes in the tax regimes applicable to oil and gas operations in a number of countries where the Company conducts its upstream operations. As a result of these trends, management estimates that the tax rate applicable to the Company's oil and gas operations is materially higher than the Italian statutory tax rate for corporate profit, which currently stands at 24 per cent.

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

TABLE OF CONTENTS

In the current uncertain financial and economic environment, governments are facing greater pressure on public finances, which may induce them to intervene in the fiscal framework for the oil and gas industry, including the risk of increased taxation, windfall taxes and even nationalizations and expropriations.

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

The present value of future net revenues from Eni's proved reserves will not necessarily be the same as the current market value of Eni's estimated crude oil and natural gas reserves

The present value of future net revenues from Eni's proved reserves may differ from the current market value of Eni's estimated crude oil and natural gas reserves. In accordance with U.S. SEC rules, Eni bases the estimated discounted future net revenues from proved reserves on the 12-month un-weighted arithmetic average of the first-day-of-the-month commodity prices for the preceding twelve months. Actual future prices may be materially higher or lower than the U.S. SEC pricing used in the calculations. Actual future net revenues from crude oil and natural gas properties will be affected by factors such as:

- the actual prices Eni receives for sales of crude oil and natural gas;
- the actual cost and timing of development and production expenditures;
- the timing and amount of actual production; and
- changes in governmental regulations or taxation.

The timing of both Eni's production and its incurrence of expenses in connection with the development and production of crude oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. Additionally, the 10 per cent. discount factor Eni uses when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with Eni's reserves or the crude oil and natural gas industry in general.

Political considerations

A substantial portion of Eni's oil and gas reserves and gas supplies are located in countries outside the EU and North America, mainly in Africa, Central Asia and Central-Southern America, where the socio-political framework and macroeconomic outlook is less stable than in the OECD countries. In those less stable countries, Eni is exposed to a wide range of additional risks and uncertainties, which could materially impact the ability of the Company to conduct its operations in a safe, reliable and profitable manner.

As of 31 December 2017, approximately 80% of Eni's proved hydrocarbon reserves were located in such countries and 60% of Eni's supplies of natural gas came from outside OECD countries. Adverse political, social and economic developments, such as internal conflicts, revolutions, establishment of non-democratic regimes, protests, strikes and other forms of civil disorder, contraction of economic activity and financial difficulties of the local governments with repercussions on the solvency of state institutions, inflation levels, exchange rates and similar events in those non-OECD countries may negatively impair Eni's ability to continue operating in an economically viable way, either temporarily or permanently, and Eni's ability to access oil and gas reserves. In particular, Eni faces risks in connection with the following, possible issues:

- lack of well-established and reliable legal systems and uncertainties surrounding the enforcement of contractual rights;
- unfavourable enforcement of laws, regulations and contractual arrangements leading, for example, to expropriation, nationalization or forced divestiture of assets and unilateral cancellation or modification of contractual terms. Eni is

facing increasing competition from state-owned oil companies that are partnering Eni in a number of oil and gas projects and properties in the host countries where Eni conducts its upstream operations. These state-owned oil companies can unilaterally change contractual terms and other conditions of oil and gas projects in order to obtain a larger share of profit from a given project, thereby reducing Eni's profit share. They can also enforce different interpretations of contractual clauses relating to the recovery of certain expenses incurred by the Company to produce hydrocarbons reserves in any given project. In Kazakhstan we recorded a risk provision to account for a dispute with the First Party (i.e. the national oil company) about the sharing of the profit oil in a petroleum contract with regard to past fiscal years;

- sovereign default or serious financial crises of those countries due to the fact that they rely heavily on petroleum revenues to sustain public finance and petroleum revenues have dramatically contracted during the recent, three-year long oil downturn. Financial difficulties at country level often translate into failure on part of state-owned companies and agencies to fulfill their financial obligations towards Eni relating to funding capital commitments in projects operated by Eni or to timely paying supplies of equity oil and gas volumes;

- restrictions on exploration, production, imports and exports;

- tax or royalty increases (including retroactive claims);

- political and social instability which could result in civil and social unrest, internal conflicts and other forms of protest and disorder such as strikes, riots, sabotage, acts of violence and similar incidents. These risks could result in disruptions to economic activity, loss of output, plant closures and shutdowns, project delays, the loss of assets and threat to the security of personnel. They may disrupt financial and commercial markets, including the supply of and pricing for oil and natural gas, and generate greater political and economic instability in some of the geographical areas in which Eni operates;

- difficulties in finding qualified suppliers in critical operating environments; and

- complex processes of granting authorisations or licences affecting time-to-market of certain development projects.

Areas where Eni operates and where the Company is particularly exposed to political risk include, but are not limited to: Libya, Egypt, Algeria, Nigeria, Angola, Kazakhstan, Venezuela, Iraq and Russia. Additionally, any possible reprisals because of military or other action, such as acts of terrorism in Europe, the United States or elsewhere, could have a material adverse effect on Eni’s business, results of operations and financial condition.

In recent years, Eni’s operations in Libya were materially affected by the revolution of 2011 and the regime change, which caused a prolonged period of political and social instability. In 2011 Eni’s operations in the Country were shut down almost the entire year due to security issues with a material impact on results of operation and cash flow; in subsequent years we have experienced frequent disruptions at our operations albeit of a smaller scale than in 2011 due to security threats to our installations. Over the last couple of years, Eni’s oil activities in the country have come in line with management expectations, reflecting a certain degree of normalization in the Country internal situation and improving security conditions. In 2017, Eni’s production in Libya was 377 KBOE/d, which represents the highest level of Eni’s production in the Country on record. Despite this and other positive developments, Libya’s geopolitical situation continues to represent a source of risk and uncertainty for the foreseeable future. Currently, Libya represents approximately 20% of the Group’s total production; this incidence is forecasted to decrease in the medium term. In the event of major adverse events such as the resumption of internal conflict, acts of war, sabotage, social unrest, clashes and other forms of civil disorder, Eni could be forced to temporarily interrupt or reduce its producing activities at the Libyan plants, negatively affecting Eni’s results of operations, cash flow and business prospects.

Venezuela is currently experiencing a situation of financial stress amidst an economic downturn due to lack of resources to support the development of the country’s hydrocarbons reserves. The situation has been made worse by certain international sanctions targeting the country’s financial system, described below. We expect that the financial outlook of Venezuela will negatively impact our ability to recover our investments in the country. See Item 5 for a discussion of the impairment losses incurred by Eni at its assets in Venezuela in 2017.

Also Nigeria is undergoing a situation of financial stress, which has translated into continuing delays in collecting overdue trade receivables and operational credits and the incurrence of credit losses. Further, Eni's activities in Nigeria have been impacted in recent years by continuing incidences of theft, acts of sabotage and other similar disruptions, which have jeopardized the Company's ability to conduct operations in full security, particularly in the onshore area of the Niger Delta. Eni expects that those risks will continue to affect Eni's operations in Nigeria and other countries.

TABLE OF CONTENTS

It is possible that the Group may incur further impairment or credit losses in future reporting periods depending on the evolution of the financial crises of the Countries where the Group is conducting oil&gas operations.

In Egypt, Eni plans to invest significantly in the next four-year plan, in particular to complete the development plan at the Zohr offshore gas field. We will continue monitoring the counterparty risk considering the expected increase in volumes of gas supplied to national oil companies due to the production ramp up at the Zohr project in the next years.

Eni closely monitors political, social and economic risks of 71 countries in which it has invested or intends to invest, in order to evaluate the economic and financial return of certain projects and to selectively evaluate projects. While the occurrence of those events is unpredictable, the occurrence of any such events could adversely affect Eni's results from operations, cash flow and business prospects, also including the counterparty risk arising from the financing exposure of Eni in case state-owned entities, which are party to Eni's upstream projects for developing hydrocarbons, fail to reimburse due amounts.

An escalation of the political crisis in Russia and Ukraine could affect Eni's business in particular and the global energy supply generally. Sanctions against Venezuela could negatively affect the Country's financial outlook, which could in turn negatively affect the Company.

In response to the Russia-Ukraine crisis, the European Union and the United States have enacted sanctions targeting, inter alia, the financial and energy sectors in Russia by restricting the supply of certain oil and gas items and services to Russia and certain forms of financing. Eni's activities potentially targeted by the sanction regime comprise the upstream projects executed in Russia or with Russian partners that have been targeted by sectorial restrictive measures.

Eni has adapted its activities to the applicable sanctions and will adapt its business to any further restrictive measures that could be adopted by the relevant authorities. Recently, the US government has tightened the sanction regime against Russia by enacting the "Countering America's Adversaries Through Sanctions Act". In response to these new measures, the Company could possibly refrain from pursuing business opportunities in Russia or could slow down, postpone or put on hold certain exploration projects under execution in Russia.

It is possible that wider sanctions targeting the Russian energy, banking and/or finance industries may be implemented. Further sanctions imposed on Russia, Russian citizens or Russian companies by the international community, such as restrictions on purchases of Russian gas by European companies or measures restricting dealings with Russian counterparties, could adversely impact Eni's business, results of operations and cash flow. Furthermore, an escalation of the international crisis, resulting in a tightening of sanctions, could entail a significant disruption of energy supply and trade flows globally, which could have a material adverse effect on the Group's business, financial conditions, results of operations and prospects.

In 2017, the US Administration enacted certain financing sanctions against Venezuela, which restrict the Country's or its affiliates' ability to access capital markets by prohibiting new transactions relating to equity or debt instruments with a longer maturity than a pre-set threshold. These sanctions have a limited, direct effect on Eni's activities, which however are affected by the worsening financial outlook of the Country.

Risks in the Company's Gas & Power business

Risks associated with the trading environment and competition in the gas market

The outlook of the European gas market remains muted due to continued oversupplies, exacerbated by increased availability of liquefied natural gas ("LNG") on global scale, and weak demand dynamics. Growth in gas demand has been dampened by sluggish macroeconomic activity in the Eurozone, the increasing use of renewable sources in the production of electricity and competition from cheaper fossil fuels (like coal) in firing thermoelectric production. Management does not expect any meaningful acceleration in gas demand growth in Italy and in Europe and is forecasting flat growth in Europe and Italy until 2021.

TABLE OF CONTENTS

Against the backdrop of a challenging competitive environment, Eni anticipates a number of risk factors to the profitability outlook of the Company's gas marketing business over the four-year planning period, considering the Company's operational constraints dictated by its long-term supply contracts with take-or-pay clauses and its structure of fixed costs linked to the transportation rights at the main European backbones booked for multi-year periods. Such risk factors include continuing oversupplies, pricing pressures, volatile margins and the risk of deteriorating spreads of Italian spot prices versus continental benchmarks. The results of Eni's wholesale business are particularly exposed to the volatility of the spreads between spot prices at European hubs and Italian spot prices because the Group's supply costs are mainly linked to prices at European hubs, whereas a large part of the Group's selling volumes are linked to Italian spot prices which, historically, have been higher. This price differential enables the Company to recover its fixed operating expenses in the gas wholesale business. In the next few years we expect that spot prices in Italy could align with prices at continental hubs due to a number of trends. These include possible developments in the regulatory environment aiming at increasing the liquidity at Italian hubs by granting access at international pipelines connecting Italy to Northern Europe and at Italian regasification terminal to new market operators; as well as the entry into operations of a project to import gas from the Caspian region to Italy by means of a new pipeline.

Eni's management will continue to execute its strategy of renegotiating the Company's long-term gas supply contracts in order to align pricing and volume terms to current market conditions as they evolve. The revision clauses provided by these contracts state the right of each counterparty to renegotiate the economic terms and other contractual conditions periodically, in relation to ongoing changes in the gas scenario.

Management believes that the outcome of those renegotiations is uncertain in respect of both the amount of the economic benefits that will be ultimately obtained and the timing of recognition of profit. Furthermore, in case Eni and the gas suppliers fail to agree on revised contractual terms, the claiming party has the ability to open an arbitration procedure to obtain revised contractual conditions. However, the suppliers might also file counterclaims with the arbitration panel seeking to dismiss Eni's request for a price review. All these possible developments within the renegotiation process could increase the level of risks and uncertainties relating the outcome of those renegotiations.

Current, negative trends in gas demands and supplies may impair the Company's ability to fulfil 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 and anticipating certain trends in gas demand, which thus far have failed to materialize, Eni has signed a number of long-term gas supply contracts with national operators of certain key producing countries. Most European gas supplies are sourced from those countries (Russia, Algeria, Libya, the Netherlands and Norway).

These contracts include take-or-pay clauses whereby the Company is required to off-take minimum, pre-set volumes of gas in each year of the contractual term or, in case of failure, to pay the whole price, or a fraction of that price, up to the minimum contractual quantity. Similar considerations apply to ship-or-pay contractual obligations. Long-term gas supply contracts with take-or-pay clauses expose the Company to a volume risk, as the Company is contractually required to purchase minimum annual amounts of gas or, in case of failure, to pay the underlying price.

Management believes that the current market outlook which will be negatively affected by continued oversupplies, weak demand growth, strong competitive pressures as well as any possible change in sector-specific regulation represents a risk to the Company's ability to fulfil its minimum take obligations associated with its long-term supply contracts.

Risks associated with sector-specific regulations in Italy

Risks associated with the regulatory powers entrusted to the Italian Regulatory Authority for Energy, Networks and Environment in the matter of pricing to residential customers

Eni's Gas & Power segment is subject to regulatory risks mainly in its domestic market in Italy. Developments in the regulatory framework may negatively affect future sales margins of gas and electricity,

TABLE OF CONTENTS
operating results and cash flow. The following describes the most important aspects of the ongoing regulatory framework of the gas&power sector in Italy.
The Italian Regulatory Authority for Energy, Networks and Environment (the "Authority") is entrusted with certain powers in the matter of natural gas pricing. Specifically, the Authority retains a 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. Accordingly, decisions of the Authority on these matters may limit the ability of Eni to pass an increase in the cost of the raw material onto final consumers of natural gas.
The Authority has established a benchmark gas price formula in favour of residential customers which are consuming 200,000 cubic meters of gas or less per year destined to civil utilizations (heating, cooking, air conditioning). In 2013, the Authority changed this pricing formula by introducing a full indexation of the raw material cost component of the tariff to spot prices, by this way replacing the former oil-linked indexation. The new regulatory regime was introduced in a market scenario where gas spot prices were significantly lower than gas prices under long-term, oil-linked contracts, as the Brent price at the time was about 100 $/BBL. Subsequently, the Authority introduced a compensation mechanism to promote the renegotiation of long-term gas supply contracts. This compensation mechanism was intended to mitigate the impact of the new tariff regime to operators with long-term supply contracts (typically oil-linked) by reimbursing them part of the higher long term gas supply costs which would be no longer recoverable through the tariffs. This compensation mechanism applied to the three thermal years from October 2013 through September 2016 and helped Eni mitigate the negative impact of the changed pricing regime to its final customers in the retail segment.
The indexation of the cost of the raw material to the spot prices of gas is expected to remain effective until September 2018. Subsequently, management forecasts a possible increase in competition in the retail segment due to the effects of Italian Law 124/2017 designed to further de-regulate the retail gas sector by eliminating the legal requirement of a gas price benchmark established pursuant to the administrative powers of the Authority. Italian Law 124/2017 has established measures intended to make retail customers knowledgeable about the possibility to choose among competing gas supply offers as well as to enable customers to evaluate competing offers against a benchmark. From March 2018, gas selling companies are required to provide customers in addition to their basic offer two additional pricing formulas, one at fixed price, the other at variable price, with contractual conditions in each case aligned with certain requirements established by the Authority.
Environmental, health and safety regulations
Eni has incurred in the past, and will continue incurring, material operating expenses and expenditures, and is exposed to business risk in relation to compliance with applicable environmental, health and safety regulations in future years, including compliance with any national or international regulation on GHG emissions
Eni is subject to numerous EU, international, national, regional and local laws and regulations regarding the impact of its operations on the environment and health and safety of employees, contractors, communities and properties. Generally, these laws and regulations require 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, including refinery and petrochemical plant operations, limit or prohibit drilling activities in certain protected areas, require to remove and dismantle drilling platforms and other equipment and well plug-in once oil and gas operations have terminated, provide for measures to be taken to protect the safety of the workplace and health of communities involved by the Company's activities, and impose criminal or civil liabilities for polluting the environment or harming employees' or communities' health and safety resulting from the Group's operations.
These laws and regulations also regulate the emission of substances and pollutants, the handling of hazardous materials and discharges to surface and subsurface of water resulting from the operation of oil and natural gas extraction and processing plants, petrochemical plants, refineries, service stations, vessels, oil carriers, pipeline systems and other facilities owned by Eni. In addition, Eni's operations are subject to laws and regulations relating to the production, handling, transportation, storage, disposal and treatment of waste materials.

TABLE OF CONTENTS

Breaches of environmental, health and safety laws as well as negligent or willful release of pollutants into the atmosphere, the soil or groundwater would expose the Company's employees to criminal and civil liability and the Company to the incurrence of liabilities associated with compensation for environmental, health or safety damage, expenses for environmental remediation and clean-up as well as damage to its reputation. Additionally, in the case of violation of certain rules regarding the safeguard of the environment and safety in the workplace, the Company may be liable for negligent or willful conduct on part of its employees as per Italian 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 in the foreseeable future to comply with laws and regulations and to safeguard the environment, safety in the workplace, health of employees, contractors and communities involved by the Company operations, including:

- costs to prevent, control, eliminate or reduce certain types of air and water emissions and handle waste and other hazardous materials, including the costs incurred in connection with government action to address climate change;
- remedial and clean-up measures related to environmental contamination or accidents at various sites, including those owned by third parties (see discussion below);
- damage compensation claimed by individuals and entities, including local, regional or state administrations, should Eni cause any kind of accident, oil spill, well blowouts, pollution, contamination, emission of GHG above permitted levels or of any other hazardous gases or other environmental liabilities as a result of its operations or if the Company is found guilty of violating environmental laws and regulations; and
- costs in connection with the decommissioning and removal of drilling platforms and other facilities, and well plugging at the end of oil&gas field production.

Furthermore, in those countries where Eni is currently operating new laws and regulations, the imposition of tougher licence requirements, increasingly strict enforcement or new interpretations of existing laws and regulations or the discovery of previously unknown contamination may also cause Eni to incur material costs resulting from actions taken to comply with such laws and regulations, including:

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

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

Risks of environmental, health and safety incidents and liabilities are inherent in many of Eni's operations and products. Management believes that Eni adopts high operational standards to ensure safety in running its operations and safeguard of the environment and the health of employees, contractors and communities. In spite of such measures, it is possible that incidents like blowouts, oil spills, contaminations, pollution, and release in the air, soil and ground water of pollutants and other dangerous materials, liquids or gases, and other similar events could occur that would result in damage, also of large proportion and reach, to the environment, employees, contractors, communities and property. The occurrence of any such events could have a material adverse impact on the Group's business, competitive position, cash flow, results of operations, liquidity, future growth prospects, shareholders' returns and damage to the Group's reputation.

As an example of said potential risks, operations at the Val d'Agri Oil Center (COVA) were shut down for a full quarter (from April 18, 2017 to July 18, 2017) became necessary following the detection of a small quantities of oil in the external area bordering the COVA. Notwithstanding the prompt and effective remedial measures taken by Eni, the shutdown of COVA negatively affected the Group results and cash flow in 2017. A shutdown also occurred at the Goliat platform offshore the Barents Sea due to an order from the Petroleum Safety Authority of Norway, which detected a failure at the electric engine of the facility.

TABLE OF CONTENTS

Eni has incurred in the past and may incur in the future material environmental liabilities in connection with the environmental impact of its past and present industrial activities. Eni is also exposed to claims under environmental requirements and, from time to time, such claims have been made against us. Furthermore, environmental requirements and regulations in Italy and elsewhere typically impose strict liability. Strict liability means that in some situations Eni could be exposed to liability for clean-up and remediation costs, natural resource damages, and other damages as a result of Eni's conduct of operations that was lawful at the time it occurred or of the conduct of prior operators or other third parties. In addition, plaintiffs may seek to obtain compensation for damage resulting from events of contamination and pollution or in case the Company is found liable of violations of any environmental laws or regulations.

In Italy, Eni is exposed to the risk of expenses and environmental liabilities in connection with the impact of its past activities at certain industrial hubs where the Group's products were produced, processed, stored, distributed or sold, such as chemical plants, mineral-metallurgic plants, refineries and other facilities, which were subsequently disposed of, liquidated, closed or shut down. At these industrial hubs, Eni has undertaken a number of initiatives to remediate and to clean up proprietary or concession areas that were allegedly contaminated and polluted by the Group's industrial activities. State or local public administrations have sued Eni for environmental and other damages and for clean-up and remediation measures in addition to those which were performed by the Company, or which the Company committed to perform. In some cases, Eni has been sued for alleged breach of criminal laws (for example for alleged environmental crimes such as failure to perform soil or groundwater reclamation, environmental disaster and contamination amongst others).

Although Eni believes that it may not be held liable for having exceeded in the past pollution thresholds that are unlawful according to current regulations but were allowed by laws then effective, nor because the Group took over operations from third parties, it cannot be excluded that Eni could potentially incur such environmental liabilities.

Eni's financial statements account for provisions relating to the costs to be incurred with respect to clean-ups and remediation of contaminated areas and groundwater for which a legal or constructive obligation exists and the associated costs can be reasonably estimated in a reliable manner, regardless of any previous liability attributable to other parties. The accrued amounts represent management's best estimates of the Company's existing liabilities.

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

As a result of those risks, environmental liabilities could be substantial and could have a material adverse effect on Eni's, results of operations, financial condition, liquidity business prospects, reputation and shareholders' value, including dividends and the share price.

Rising public concern related to climate change has led and could lead to the adoption of worldwide laws and regulations which could result in a decrease of demand for hydrocarbons and increased compliance costs for the Company. Eni is also exposed to risks of technological breakthrough in the energy field and risks of extreme meteorological events linked to the climate change. All these developments may adversely affect the Group's profitability, businesses outlook and reputation

Growing worldwide public concern over greenhouse gas (GHG) emissions and climate change, as well as increasingly regulations in this area, could adversely affect the Group's businesses and reputation, increase its operating costs and reduce its profitability and shareholders returns. Those risks may emerge in the short and medium-term, as well as over the long-term.

TABLE OF CONTENTS

The scientific community has established a link between climate change and increasing GHG emissions. The worldwide goal to limit global warming has led, and we expect it to continue to lead, to new laws and regulations designed to reduce GHG emissions that could bring about a gradual reduction in the use of fossil fuel over the long-term, notably through the diversification of the energy mix.

Some governments have introduced carbon pricing mechanisms, which can be an effective measure to reduce GHG emissions at the lowest overall cost to society. Eni expects that more governments will adopt similar schemes and that a growing share of the Group GHG emissions will be subject to regulation in the short to medium term. We also expect that governments require companies to apply technical measures to reduce their GHG emissions. We are already incurring operating costs related to our participation in the European Emission Trading Scheme, whereby we need to purchase on the open markets emission allowances in case our GHG emissions exceed a pre-set limit established at European level by regulations in force (see Note No. 38 to the Financial Statements). In 2017 to comply with this carbon scheme, we purchased on the open market allowances corresponding to 11 million tonnes. In certain jurisdictions, we are already subject to carbon pricing schemes (for example in Norway). Due to likelihood of new regulations in this area, we expect additional compliance obligations with respect to the release, capture, and use of carbon dioxide that could result in increased investments and higher project costs for Eni and could have a material adverse effect on Eni’s liquidity, results of operations, and financial condition.

The adoption and implementation of regulations that require reporting of GHG or otherwise limit GHG emissions from the Group’s equipment and operations could require us to incur costs to monitor and report on GHG emissions or install new equipment to reduce GHG emissions associated with the Group’s operations.

In the long-term, we expect that changes in environmental requirements targeting the reduction of GHG emissions (including land use policies responsive to environmental concerns) may increasingly focus on suppressing the demand for fossil fuels, which could negatively impact demand for oil and natural gas. State, national, and international governments and agencies have been evaluating climate-related legislation and other regulatory initiatives that would restrict emissions of GHG in areas in which Eni conducts business. Because Eni’s business depends on the global demand for oil and natural gas, in case existing or future laws, regulations, treaties, or international agreements related to GHG and climate change, including incentives to preserve energy or use alternative energy sources, technological breakthrough in the field of renewable energies or mass-adoption of electric vehicles reduce the worldwide demand for oil and natural gas, this could significantly and negatively affect Eni’s results of operations, liquidity, business prospects and shareholders’ returns.

Natural gas, the least GHG-emitting fossil energy source, represented approximately 50% of Eni’s production in 2017 on an available-for-sale basis; as of December 31, 2017, gas reserves represented approximately 51% of Eni’s total proved reserves of its subsidiary undertakings and joint ventures. Eni’s portfolio exposure is reviewed annually against changing GHG regulatory regimes and physical conditions to identify emerging risks. To test the resilience of new projects, Eni assesses potential costs associated with GHG emissions when evaluating all new capital projects. New projects’ internal rates of return are stress-tested against two sets of assumptions: i) a uniform cost estimated by Eni’s management per ton of carbon dioxide (CO2) equivalent to the total GHG emissions of each capital project; ii) the hydrocarbon prices and cost of CO2 emissions adopted in the International Energy Agency (IEA) Sustainable Development Scenario “IEA SDS”. This stress test is performed both when the final investment decision is made and, on a regular basis, to monitor the progress of each project. The review performed at the end of 2017 concluded that the internal rates of return of Eni’s ongoing projects in aggregate would be only marginally affected by a carbon pricing mechanism. The project development process features a number of checks that may require the development of detailed GHG and energy management plans. High-emitting projects undergo additional sensitivity testing, including the potential for future CCS (Carbon Capture and Storage) projects. Projects in the most GHG-exposed asset classes have GHG intensity targets that reflect standards sufficient to allow them to compete and prosper in a more CO2 regulated future. These processes can lead to projects being stopped, designs being changed, and potential GHG mitigation investments being identified, in preparation for when regulation would make these investments commercially compelling.

Furthermore, management performed a review of the recoverability of the book values of the Company’s oil & gas assets under the assumptions of the IEA SDS. This review covered all of the oil & gas cash generating unit (CGUs) that are regularly tested for impairment in accordance to IAS 36. The IEA

20

TABLE OF CONTENTS

SDS sets out an energy pathway consistent with the goal of achieving universal energy access by 2030 and of reducing by a half energy-related CO2 emissions and premature deaths from air pollution by 2040, compared to projections with no further policy action. The IEA SDS forecasts that demand for oil is going to peak in 2020. The pricing assumptions are consistent with Eni's scenario in the case of crude oil, while the gas prices projected by the IEA SDS are higher by an approximately 15% than Eni's forecast. CO2 emissions will be priced at 140 $ per ton in real terms in 2040 higher than Eni's CO2 pricing assumptions for the medium-long term. The sensitivity test performed at Eni's oil&gas CGUs under the IEA SDS confirmed the resiliency of Eni's asset portfolio with a 4% reduction in the aggregate fair value of Eni's properties due to the CO2 pricing assumptions.

Some scientists have concluded that increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as the increased frequency and severity of hurricanes storms, droughts, floods or other extreme climatic events that could interfere with Eni's operations and damage Eni's facilities. Furthermore, Eni's operations, particularly offshore production of oil and natural gas, are exposed to extreme weather phenomena that can result in material disruption to Eni's operations and consequent loss or damage of properties and facilities, as well as a loss of output, loss of revenues, increasing maintenance and repair expenses and cash flow shortfall. If any such effects were to occur because of climate change or otherwise, they could have an adverse effect on the Group's assets and operations.

Finally, there is a reputational risk linked to the possibility that oil companies may be perceived by institutions and the general public as the entities mainly responsible of the climate change. This could possibly make Eni's shares less attractive to investment funds and individual investors who assess the risk profile of companies against their environmental and social footprint when making investment decisions.

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

Eni is the defendant in a number of civil actions and administrative proceedings. In addition to existing provisions accrued, as of December 31, 2017 to account for ongoing proceedings, in future years Eni may incur significant losses in addition to the amounts already accrued in connection with pending or future legal proceedings due to: (i) uncertainty regarding the final outcome of each proceeding; (ii) the occurrence of new developments that management could not take into consideration when evaluating the likely outcome of each proceeding in order to accrue the risk provisions as of the date of the latest financial statements; (iii) the emergence of new evidence and information; and (iv) underestimation of probable future losses due to the circumstance that they are often inherently difficult to estimate. Certain legal proceedings and investigations to which Eni or its subsidiaries or its officers and employees are parties involve the alleged breach of anti-bribery and anti-corruption laws and regulations and other ethical misconduct. Such proceedings are described in Note 38 to the Consolidated Financial Statements, under heading "Legal Proceedings". Ethical misconduct and noncompliance with applicable laws and regulations, including noncompliance with anti-bribery and anti-corruption laws, by Eni, its officers and employees, its partners, agents or others that act on the Group's behalf, could expose Eni and its employees to criminal and civil penalties and could be damaging to Eni's reputation and shareholder value.

Risks from acquisitions

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

Risks deriving from Eni's exposure to weather conditions

Significant changes in weather conditions in Italy and in the rest of Europe from year to year may affect demand for natural gas and some refined products. In colder years, demand for such products is

TABLE OF CONTENTS

higher. Accordingly, the results of operations of the Gas & Power segment and, to a lesser extent, the Refining & Marketing business, as well as the comparability of results over different periods may be affected by such changes in weather conditions.

Eni's crisis management systems may be ineffective

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

Exposure to financial risk

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

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

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

The Group's approach to risk management includes identifying, evaluating and managing the financial risk using a top-down approach whereby the Board of Directors is responsible for establishing the Group risk management strategy and setting the maximum tolerable amounts of risk exposure. The Group's Chief Executive Officer is responsible for implementing the Group risk management strategy, while the Group's Chief Financial Officer is in charge of defining policies and tools to manage the Group's exposure to financial risk, as well as monitoring and reporting activities.

Various Group committees are in charge of defining internal criteria, guidelines and targets of risk management activities consistent with the strategy and limits defined at Eni's top level, to be used by the Group's business units, including monitoring and controlling activities. Although Eni believes it has established sound risk management procedures, trading activities involve elements of forecasting and Eni is exposed to the risks of market movements, of incurring significant losses if prices develop contrary to management expectations and of default of counterparties.

Exchange rate risk

Movements in the exchange rate of the euro against the U.S. dollar can have a material impact on Eni's results of operations. Prices of oil, natural gas and refined products generally are denominated in, or linked to, U.S. dollars, while a significant portion of Eni's expenses are incurred in euros. Accordingly, a depreciation of the U.S. dollar against the euro generally has an adverse impact on Eni's results of operations and liquidity because it reduces booked revenues by an amount greater than the decrease in U.S. dollar-denominated expenses and may also result in significant translation adjustments that impact Eni's

TABLE OF CONTENTS

shareholders' equity. The Exploration & Production segment is particularly affected by movements in the U.S. dollar versus the euro exchange rates as the U.S. dollar is the functional currency of a large part of its foreign subsidiaries and therefore movements in the U.S. dollar versus the euro exchange rate affect year-on-year comparability of results of operations.

Susceptibility to variations in sovereign rating risk

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

Interest rate risk

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

Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the Group may not be available, or the Group is unable to sell its assets on the marketplace in order to meet short-term financial requirements and to settle obligations. Such a situation would negatively affect the Group results of operations and cash flows as it would result in Eni incurring higher borrowing expenses to meet its obligations or, under the worst conditions, the inability of Eni to continue as a going concern. Global financial markets are volatile due to a number of macroeconomic risk factors, including the financial situation of certain hydrocarbons-exporting countries whose financial conditions have sharply deteriorated following the protracted downturn in crude oil prices. In the event of extended periods of constraints in the financial markets, or if Eni is unable to access the financial markets (including cases where this is due to Eni's financial position or market sentiment as to Eni's prospects) at a time when cash flows from Eni's business operations may be under pressure, Eni's ability to maintain Eni's long-term investment program may be impacted with a consequent effect on Eni's growth rate, and may impact shareholder returns, including dividends or share price.

The oil and gas industry is capital intensive. Eni makes and expects to continue to make substantial capital expenditures in its business for the exploration, development, exploitation and production of oil and natural gas reserves. The Company's capital budget for the four-year plan 2018 – 2021 amounts to approximately euro 32 billion. The Company has budgeted approximately euro 7.7 billion for capital expenditures in 2018. The Company is managing to contain capital expenditures without necessarily sacrificing growth leveraging on capital discipline, phased approach to major projects and the reduction of idle capital through the optimization of the time-to-market of the reserves.

Historically, Eni's capital expenditures have been financed with cash generated by operations, proceeds from asset disposals, borrowings under its credit facilities and proceeds from the issuance of debt and bonds.

The actual amount and timing of future capital expenditures may differ materially from Eni's estimates as a result of, among other things, changes in commodity prices, available cash flows, lack of access to capital, actual drilling results, the availability of drilling rigs and other services and equipment, the availability of transportation capacity, and regulatory, technological and competitive developments.

Eni's cash flows from operations and access to capital markets are subject to a number of variables, including but not limited to:

- the amount of Eni's proved reserves;

- the volume of crude oil and natural gas Eni is able to produce and sell from existing wells;
- the prices at which crude oil and natural gas are sold;
- Eni's ability to acquire, find and produce new reserves; and
- the ability and willingness of Eni's lenders to extend credit or of participants in the capital markets to invest in Eni's bonds.

If revenues or Eni's ability to borrow decrease significantly due to factors such as a prolonged decline in crude oil and natural gas prices, Eni might have limited ability to obtain the capital necessary to sustain its planned capital expenditures. If cash generated by operations, cash from asset disposals, or cash available under Eni's liquidity reserves or its credit facilities is not sufficient to meet capital requirements, the failure to obtain additional financing could result in a curtailment of operations relating to development of Eni's reserves, which in turn could adversely affect its business, financial condition, results of operations, and cash flows and its ability to achieve its growth plans. These factors could also negatively affect shareholders' returns, including the amount of cash available for dividend distribution as well as the share price.

In addition, funding Eni's capital expenditures with additional debt will increase its leverage and the issuance of additional debt will require a portion of Eni's cash flows from operations to be used for the payment of interest and principal on its debt, thereby reducing its ability to use cash flows to fund capital expenditures and dividends.

Credit risk

Credit risk is the potential exposure of the Group to losses in case counterparties fail to perform or pay due amounts. Credit risks arise from both commercial partners and financial ones. In the last few years, the Group has experienced a level of counterparty default higher than in previous years due to the severity of the economic and financial downturn that has negatively affected several Group counterparties, customers and partners. Consequently, the amount of trade and other receivables overdue at the balance sheet date has become an area of issue. Our E&P business is significantly exposed to the credit risk because of the deteriorated financial outlook of many oil-producing countries, particularly Venezuela and Nigeria, due to a three-year long downturn in oil prices, which has negatively impacted petroleum revenues and cash reserves. The financial difficulties of those countries have extended to state-owned oil companies and other national agencies who are partnering Eni in the execution of development projects of hydrocarbons reserves or who are the buyers of Eni's equity production in a number of oil&gas projects. These trends have limited Eni's ability to fully recover or to collect timely its trade or financing receivable or its investments towards those entities. For further information, see the paragraph "Political Considerations" above. The Gas & Power business has also experienced a higher-than-average level of counterparty default in its segment of supplying gas and electricity to the retail market due to the severity of the economic downturn in Italy. In the 2017 Consolidated Financial Statements, Eni accrued an allowance against doubtful trade accounts amounting to euro 539 million, mainly relating to the Gas & Power business segment in relation to Italian retail customers. Management believes that this business is particularly exposed to credit risk due to its large and diversified customer base, which includes a large number of medium and small-sized businesses and retail customers who have been particularly hit by the financial and economic downturn. Eni believes that the management of doubtful accounts represents an issue to the Company, which will require management focus and commitment going forward. Eni cannot exclude the recognition of significant provisions for doubtful accounts in the future. In particular, management is closely monitoring exposure to the counterpart risk in its Exploration & Production due to the magnitude of the exposure at risk and to the long-lasting effects of the oil price downturn on its industrial partners.

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

The reliability and security of Eni's digital infrastructure is critical to maintaining the availability of Eni's business applications, including the reliable operation of technology in Eni's various business operations and the collection and processing of financial and operational data, as well as the confidentiality of certain third-party information. Disruption to or breaches of Eni's critical IT services or information security systems could adversely affect the Group's operations. The Group's activities depend heavily on the

24

TABLE OF CONTENTS

reliability and security of its information technology (IT) systems. Integrity of IT systems could be compromised due to, for example, technical failure, cyber-attack (viruses, computer intrusions), power or network outages or natural disasters. The cyber threat is constantly evolving. Attacks are becoming more sophisticated with regularly renewed techniques as the digital transformation amplifies exposure to these cyber threats. The adoption of new technologies, such as the Internet of things (IoT) or the migration to the cloud, as well as the evolution of architectures for increasingly interconnected systems, are all areas where cyber security is a very important issue. As a result, the Group’s activities and assets could sustain serious damage, services to clients could be interrupted, material intellectual property could be divulged and, in some cases, personal injury, property damage, environmental harm and regulatory violations, litigation and legal liabilities could occur, potentially having a material adverse effect on the Group’s financial condition, including its operating profit and cash flow.

Claim of the Italian market regulator against Eni’s jv Saipem

Eni retains a 31% interest in Saipem which is jointly controlled with another shareholder. On March 5, 2018, the Italian securities and exchange regulator – Consob – asserted a claim against Saipem stating that the entity consolidated and separate financial statements for the year 2016 did not comply with applicable accounting rules. In the 2016 financial statement Saipem recorded impairment losses at its property, plants and equipment of €2,118 million and an allowance for doubtful accounts of €171 million. Consob is asserting that part of those impairment losses amounting to €1.3 billion and €0.1 billion of charges related to inventories and deferred tax assets should have been accrued in the financial year ended December 31, 2015. Consob is also asserting that the methodology used by Saipem to assess the discount rate of the future cash flows associated with the tangible assets is not fully compliant with generally accepted accounting principles. Saipem has expressed in a press release that it disagrees with the conclusions of Consob; however, it has committed to disclosing pro-forma statements of the financial position and of the profit and loss as at Dicember 31, 2016 including comparative data to account for the comments of Consob. On March 6, 2018, Saipem publicly disclosed that its Board of Directors resolved to file an appeal against Consob decision before the relevant judicial authorities.

On October 27, 2015 Eni and an Italian state-owned venture agreed to the divestiture of a 12.503% stake previously held in Saipem by Eni and entered into a shareholders’ agreement whereby Eni and the venture agreed to jointly control Saipem. Therefore, when the transactions closed on January 22, 2016, Saipem and its subsidiaries were derecognized from Eni’s consolidated accounts and the retained investment was classified as an investment in a joint-venture accounted under the equity method. Effective November 1, 2015 Saipem was classified in Eni’s consolidated financial statements as a discontinued operations and accounted in accordance to IFRS 5 which establishes the interruption of the amortization process and the evaluation of the disposal group at the lower of its carrying amount and the fair value given by the market value, because the recoverability of the disposal group occurs through a sale instead of its continuative use. On that date, the fair value of the disposal group was higher than its carrying amount.

In the Annual Report 2015 the interest in Saipem was aligned to its fair value which was lower than the carrying amount due to a downtrend in the market price of Saipem, thus recognizing in Eni’s consolidated accounts an impairment loss of €393 million (€173 million pertaining to Eni’s shareholders). On January 22, 2016, when Eni lost its exclusive control over the investee due to the efficacy of the shareholders’ agreement and the joint control over Saipem was established, Eni aligned again the retained interest in the entity to its fair value recording an impairment loss of €441 million in accordance to the provisions of IFRS 10. This fair value became the inception value for the subsequent accounting of the retained investment under the equity method. As of June 30, 2016 the carrying amount of Saipem investment in Eni’s books was significantly lower than the corresponding fraction of the net assets of the investee. This difference was absorbed at the closing of the financial year 2016.

Conclusively, pending the evolution of the litigation between Saipem and Consob, management believes that the accounting of the Saipem investment in Eni’s consolidated financial statements in the target reporting periods was primarily based on measurements at fair value obtained by observing market prices.

TABLE OF CONTENTS

Item 4. INFORMATION ON THE COMPANY

History and development of the Company

Eni SpA with its consolidated subsidiaries engages in the exploration, development and production of hydrocarbons, in the supply and marketing of gas, LNG and power, in the refining and marketing of petroleum products, in the production and marketing of basic petrochemicals, plastics and elastomers and in commodity trading. Eni has operations in 71 countries and 32,934 employees as of December 31, 2017.

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.

The name of the agent of Eni in the United States is Giovan Battista Di Giovanni, Washington DC – USA 601, 13th street, NW 20005.

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 46 countries, including Italy, Libya, Egypt, Norway, the United Kingdom, Angola, Congo, Nigeria, the United States, Kazakhstan, Algeria, Australia, Venezuela, Iraq, Indonesia, Ghana and Mozambique. In 2017, Eni’s average daily production amounted to 1,719 KBOE/d on an available-for-sale basis. As of December 31, 2017, Eni’s total proved reserves amounted to 6,990 mmBOE, which include subsidiary undertakings and Eni’s share of reserves of equity-accounted and proportionally consolidated entities.

Eni’s Gas & Power segment engages in the supply, trading and marketing of gas, LNG and electricity, international gas transport activities and commodity trading and derivatives. This segment also includes the activity of electricity generation, which is ancillary to the marketing of electricity. In 2017, Eni’s worldwide sales of natural gas amounted to 80.83 BCM, of which 37.43 BCM in Italy. Eni produces power at a number of operated gas-fired plants in Italy with a total installed capacity of 4.7 GW as of December 31, 2017. In 2017, electricity sold totalled 35.33 TWh. The Gas & Power segment comprises results of the Group activities intended to manage commodity risk and of asset-backed trading activities. Through the trading department of the parent company and its wholly-owned subsidiary Eni Trading & Shipping SpA, the Group engages in derivative activities targeting the full spectrum of energy commodities on both the physical and financial trading venues. This activity is designated to hedge part of the Group’s exposure to commodity risk and to optimize commercial margins by entering speculative derivative transactions. Furthermore, this activity includes the results of crude oil and products supply, trading and shipping.

Eni’s Refining & Marketing and Chemicals segment includes the results of the R&M business and of the chemicals business.

The R&M business engages in crude oil supply and refining and the marketing of petroleum products in retail and wholesale markets mainly in Italy and in the rest of Europe, as well as in the petrochemical business. In 2017, processed volumes of crude oil and other feedstock, including renewable feedstock, amounted to 24.26 mmtonnes (of which traditional refinery throughputs were 24.02 mmtonnes and green refinery throughputs were 0.24 mmtonnes) and sales of refined products were 33.20 mmtonnes, of which 25.73 mmtonnes in Italy. Retail sales of refined products at Eni’s service stations amounted to 8.54 mmtonnes in Italy and in the rest of Europe. In 2017, Eni’s retail market shares in Italy through its “Eni” branded network of service stations was 25%.

TABLE OF CONTENTS

Through its wholly-owned subsidiary Versalis, Eni engages in the production and marketing of basic petrochemical products, plastics and elastomers. Activities are concentrated in Italy and in Europe. At the end of 2017 a joint venture for the production of elastomers started operations in South Korea with a local operator. In 2017, production volumes of petrochemicals amounted to 5,818 ktonnes. The results of Versalis have been aggregated with those of R&M, in the reportable segment "R&M and Chemicals" because the two segments exhibit similar economic characteristics.
Eni's registered head office is located at Piazzale Enrico Mattei 1, Rome, Italy (telephone number: +39-0659821).
Eni branches are located in:

- San Donato Milanese (Milan), Via Emilia, 1; and
- San Donato Milanese (Milan), Piazza Ezio Vanoni, 1.

Internet address: eni.com
A list of Eni's subsidiaries is provided in "Item 18 – note 48 – Other information about investments – of the Notes on Consolidated Financial Statements".

Strategy

During the downturn in oil prices which lasted from the second half of 2014 to the end of 2017, the Company has managed to reduce its cash neutrality – i.e. the level of Brent price at which cash flow from operating activities is able to fund capital expenditures and dividend payments – and to preserve a solid balance sheet. We exited the downturn with a leverage of 0.23 as of December 31, 2017 and a cash neutrality estimated at 57 $/BBL. These targets were achieved by leveraging on cost and capital discipline, growing profitably in E&P, restructuring our loss-making mid and downstream business that are currently generating structural positive results and cash generation, and finally process simplification and streamlining.
Our exploration activity was one of the major drivers of our value-creating strategy due to its strong contribution to reserve replacement and cash generation by means of our dual exploration model. This helped the Company anticipate the cash conversion of discovered resources by divesting part of the high interests retained by Eni in its core exploration assets. In particular, in 2017 the Company closed the divestment of a 25% interest in natural gas-rich Area 4 offshore Mozambique and in the large Zohr gas discovery offshore Egypt. From 2013 our dual exploration model generated $10.3 billion of cash proceeds, without affecting the Company's growth plans. Looking forward our strategy will evolve to enhance value generation across all our businesses.
The main drivers will be:

- Growing oil & gas production with improving returns leveraging on the organic developments of our discoveries;
- Retaining a strong focus on exploration activities to ensure reserve replacement and further opportunities to deploy our dual exploration model;
- Strengthening results and cash generation in our mid and downstream businesses through new contract renegotiations, selective growth initiatives, plant optimizations, innovation in products and services, and cost efficiencies;
- Developing the green businesses;
- Pursuing margin and growth opportunities through enhanced business integration;
-

Financial discipline;

- Increased digitalization to support operations efficiency;

- Reducing the carbon footprint of the Company.

Implementation of this strategy will be supported by a capital plan of €31.6 billion, more than 80% of which will be destined to finding and developing hydrocarbons reserves.

TABLE OF CONTENTS

We believe that the action plan we have designed for the next four-year period 2018-2021 at the Company's Brent scenario of $60 in 2018 subsequently increasing to our long-term case of $72 will improve the Company's profitability and cash generation driving down our cash neutrality. See Item 5 – Management Expectations of Operation. We remain committed to our progressive dividend policy in line with the expected growth in underlying earnings and cash flow.

Strategy for a low-carbon scenario

Our path to decarbonization has four main drivers that concern both our core business activities and new energy perspectives:

- The first is to lower CO_2 emissions in all our operations
- Secondly, we will continue to expand a low cost and low carbon portfolio of oil&gas projects
- Third, we will keep on developing renewables, and
- Finally, R&D will play a key role in our decarbonization strategy.

On carbon footprint, we have already reduced our direct upstream CO_2 emissions by around 40% since 2007, improving all of our performances and efficiency ratios. By 2025 we are targeting:

- A reduction of upstream GHG emissions by 43% and methane fugitive emissions by 80% vs 2014 and
- Zero routine gas flaring

In the long-term, we will continue to rely on the strength of our resilient portfolio. We currently estimate that the average breakeven price of new projects under execution is less than 30 $/BBL, which means that our projects will stay competitive under all carbon price scenarios. Eni applies a carbon pricing sensitivity of 40 $/ton CO_2 in real terms that implies a strong readiness in our projects for emissions optimization. Even under the IEA Sustainable Development Scenario, our portfolio confirms its resilience, with a marginal reduction in our internal rates of return and in the value of our assets.

In addition, we will continue to support a widespread use of natural gas in the future energy mix with gas resources playing an increasing role in our portfolio.

In our decarbonization strategy, we plan a strong development of our green businesses, and we are planning capital expenditures of more than €1.8 billion over the next four years in these initiatives, including R&D.

In the downstream business we are currently producing bio-products from our facilities. The Venice traditional refinery underwent a re-configuration program to transform the plant into a bio-refinery with a current production of 0.24 mmtonnes and a similar industrial solution is being implemented at the Gela refinery with expected start-up at the end of 2018. The two refineries are planned to produce 1 mmtonnes per year of green-diesel by 2021, making Eni one of the top producers in Europe.

We have also launched a series of green chemical projects such as the production of intermediates from vegetable oil and a pilot project to use Guayule crops to produce natural rubber.

Finally, we will grow our new energy business to 1GW by the end of the four-year plan.

With regards to reductions in emissions, the current asset portfolio will enable Eni to save around 28 mmtonnes of CO_2 during the four-year plan 2018-2021, which includes direct and indirect emissions.

More information are provided in paragraph "Path to decarbonization" below.

TABLE OF CONTENTS

Significant business and portfolio developments

The significant business and portfolio developments that occurred in 2017 and to date in 2018 were the following:

- March 2018 – Eni and Sonangol started oil production at the Ochigufu project, in Block 15/06 of Angola's deep offshore. The field will add 25 KBBL to the current production levels. Achieved one and a half year from the presentation of the Plan of Development, this start-up is Eni's first in 2018 as well as being the first start-up of the year in Angola.

- March 2018 – Eni signed a license agreement with Zhejiang Petrochemicals for the license for the construction of two refining lines based on Eni Slurry Technology (EST). The two production lines will have a refining capacity of 3 mmtonnes per year and they will be built as part of a project for the construction of a new refinery with a capacity of 40 mmtonnes per year. Start-up is planned for 2020.

- March 2018 – Eni agreed to sell to Mubadala Petroleum a 10% stake in the Shorouk concession, offshore Egypt, where the Zohr gas field is currently producing. The agreed consideration is $934 million. The completion of the transaction is subject to the fulfillment of certain standard conditions, including all necessary authorizations from Egypt's Authorities. Following approval of this agreement, Eni will retain the operatorship of the block with a 50% interest.

- March 2018 – Eni signed in Abu Dhabi two Concession Agreements for the acquisition of a 5% stake in the Lower Zakum offshore oil field and of a 10% stake in the oil, condensate and gas offshore fields of Umm Shaif and Nasr, for a total participation fee of about $875 million and a contractual term of 40 years. Lower Zakum, located about 65 kilometers off the coast of Abu Dhabi, has a target production of 450 KBBL/d. Umm Shaif and Nasr, located about 135 kilometers from the coast of Abu Dhabi, have a target production of 460 KBBL/d.

- March 2018 – Eni signed agreements with Commonwealth Fusion Systems LLC (CFS) and the Massachusetts Institute of Technology to acquire an equity stake in CFS for the industrial development of the fusion power generation technology. Eni will support CFS to develop the first commercial power plant producing energy by fusion, a safe, sustainable, virtually inexhaustible source without any emission of pollutants and greenhouse gases. Eni will acquire a significant share in the company with an initial investment of $50 million.

- February 2018 – Eni's subsidiary Versalis and Bridgestone Americas (Bridgestone) signed a partnership agreement to develop a technology platform to commercialize guayule in the agricultural, sustainable-rubber and renewable-chemical sectors. The partnership combines Versalis' core strengths in guayule research, commercial-scale process engineering and market development for renewables with Bridgestone's leadership position in guayule agriculture and production technologies.

- February 2018 – Eni signed two Exploration and Production Agreements (EPA) with the Republic of Lebanon covering Blocks 4 and 9, in the deep waters offshore. Eni will retain a 40% interest in both blocks.

- February 2018 – Exploration activities yielded positive results with the Calypso 1 gas discovery in Block 6 (Eni operator with a 50% interest), offshore Cyprus.

-

February 2018 – Eni and its partner Qatar Petroleum have been awarded rights to Block 24 located in in the deep waters of the Cuenca Salina Basin in Mexico. Eni will operate the Block 24 with a 65% working interest.

- January 2018 – A licensing agreement was signed with Sinopec, the largest refining company in the world, for the use of the Eni Slurry Technology (EST) conversion proprietary technology. Eni will provide Sinopec with the basic engineering project related to the construction of a refining plant based on the EST, that is able to convert refining residues entirely into high-quality light products, eliminating both liquid and solid refining residues with significant environmental benefits.

- In 2017, Eni signed a number of strategic cooperation agreements in the upstream and renewable energy sectors in Kazakhstan. A first agreement provided for the acquisition by Eni of a 50% stake for exploration and production activities in the Isatay block located in the Kazakh sector of the Caspian Sea. The Isatay block is estimated to have significant oil resources and will be operated by a joint operating company established by KMG and Eni on a 50/50 basis. In addition, Eni and KMG signed an agreement to further expand upstream technology co-operation and evaluate potential joint developments in new projects. The agreement includes technical and managerial training programs for local staff. Eni, KMG and the other partners

TABLE OF CONTENTS

signed with the Ministry of Energy of the Republic of Kazakhstan, and the Kazakh Committee of geology and subsoil use, a Memorandum of Understanding to evaluate future cooperation terms in the Kazakh-Russian Pre-Caspian Basin recording certain significant oil discoveries. In addition, Eni and General Electric (GE) signed with the Minister of Energy of the Republic of Kazakhstan an agreement to promote the development of renewable energy projects in the Country. In particular, Eni and GE will co-operate to evaluate the construction of a wind power plant with approximately 50 MW capacity and further future initiatives.

- December 2017 – Eni successfully tested the Tecoalli 2 well in Area-1, offshore Mexico. The result and the revision of the reservoir models of the Amoca and Miztón fields, prompted Eni to raise its estimates of the hydrocarbon resources of Area 1, mainly crude oil.

- December 2017 – Acquired a 32.5% interest of the Evans Shoal gas field in the NT/RL7 offshore license in the northern of Australia, nearby the Darwin liquefaction gas plant, where Eni holds an interest. The agreement received all necessary approvals. Following this acquisition Eni retains the operatorship with a 65% interest.

- December 2017 – Eni signed a Petroleum Agreement (PA) with the Moroccan State Company ONHYM to enter into the Tarfaya Offshore Shallow exploration permits I-XII. Once the agreement is closed Eni will be the operator of the license with a 75% stake, while ONHYM will retain a 25% stake.

- December 2017 – Eni achieved production start-up of the Zohr gas field, in less than two years from the FID and two and a half years from discovery, located in the Shorouk offshore block in Egypt.

- In 2017 – In line with portfolio rationalization plan of the Gas & Power retail activities, Eni completed the sale to Eneco of retail activities in Belgium related to approximately 850,000 electricity and gas delivery points, representing a market share of around 10% of the Belgian market, and agreed to the divestment of the Tigàz gas activities in Hungary with the signing of an agreement with MET. Tigàz is active in the gas distribution through a 33,700 kilometers-long network and 1.2 million delivery points. The transaction is subject to regulatory approval by the relevant Authorities.

- December 2017 – Eni and Sonatrach signed a Memorandum of Understanding for the development of a partnership in the renewables sector.

- December 2017 – Eni and ExxonMobil closed the sale of a 25% indirect interest in the Area 4 block, offshore Mozambique, through the sale of a 35.7% stake in Mozambique Rovuma Venture. The agreed terms, based on the agreements of March 2017, include a cash price of approximately $2.8 billion plus the contractual adjustments up to the closing date. Following completion of the transaction, Mozambique Rovuma Venture, is now jointly by Eni and ExxonMobil with a 35.7% stake and the remaining interest of 28.6% by CNPC.

- December 2017 – Eni, together with its Area 4 Partners, closed the project financing of Coral South FLNG construction project. The financing agreement was subscribed by 15 major international banks and guaranteed by 5 Export Credit Agencies. Coral South FLNG is the first project sanctioned by the Area 4 Partners for the development of the significant gas resources discovered by Eni and its Partners in the Rovuma Basin offshore Mozambique.

- November 2017 – Eni signed with Sonangol an agreement to increase to 48% Eni's interest in the Cabinda North block onshore Angola, which was previously participated by Eni with a 15% interest, also acquiring operatorship. The block is located in a little-known oil basin, where Eni plans to leverage on the mining knowledge acquired in the exploration and development activities progressed in nearby areas of the Republic of Congo.

- November 2017 – Started production of elastomers at the Lotte Versalis Elastomers (LVE) joint venture. The industrial complex consists of three plants with a capacity of 200 ktonnes per year for the production of elastomers for tyre and other components in the automotive industries.

- November 2017 – signed with the Government of the Sultanate of Oman and the state oil company OOCEP an Exploration and Production Sharing Agreement for the Block 52, offshore Oman. Concurrently Eni signed an agreement to assign an interest in the Block to Qatar Petroleum oil company. The agreement is subject to approval by the relevant Authorities of the country. Following approval of these agreements, Eni will retain the operatorship of the block with a 55% interest.

- October 2017 – Eni closed the sale of a 30% stake in the Shorouk concession, offshore Egypt where the Zohr gas field is located, to Rosneft.

TABLE OF CONTENTS

- September 2017 – Eni and China National Petroleum Corporation (CNPC) signed a cooperation agreement, covering activities in China and overseas, in order to cooperate in the oil&gas exploration and production, gas and LNG value chain, trading and logistics opportunities, refining and petrochemicals.

- May 2017 – Production started up at the Integrated Oil & Gas Development project in the Offshore Cape Three Points (OCTP) in Ghana, operated by Eni with a 44.44% interest.

- May 2017 – Eni started LNG production from the Jangkrik Project in the Muara Bakau block, deep offshore Indonesia, ahead of schedule by means of ten offshore wells linked to the Floating Production Unit (FPU) with a production of approximately 630 mmCF/d (equal to 120 KBOE/ d). The LNG is sold under long-term contracts, partly to PT Pertamina and partly to Eni, which will sell up to 11 mmtonnes for 15 years as part of the supply agreement signed with the Pakistan LNG state company.

- April 2017 – Exploration activity in Libya yielded positive results with a new gas and condensates discovery in the contractual area D (Eni's interest 50%). The discovery is located nearby to the Bouri (Eni's interest 50%) and Bahr Essalam (Eni's interest 50%) production fields. The Country's authorities extended the exploration license period until 2019, without additional commitment activities. The exploration success is in line with Eni's exploration strategy of focusing on near-field incremental activities.

- March 2017 – Obtained majority stakes in two exploration blocks offshore Ivory Coast. The two deep offshore blocks cover a total area of about 2,850 square kilometers. Eni will operate and hold a 90% stake in both blocks, with the state-owned company Petroci retaining the remaining 10% interest.

- March 2017: Eni and Gazprom signed a Memorandum of Understanding for evaluating the prospects for cooperation in developing the Southern corridor for gas supplies from Russia to European countries, including Italy, as well as the updating of the Russia-Italy gas supply agreements.

- March 2017: finalized a farm-in agreement to acquire a 50% interest of Block 11, Offshore Cyprus, which will be operated by Total. The exploration area covers 2,215 square kilometers, nearby the Zohr discovery in the Egyptian offshore. Block 11 is expected to be drilled within 2017.

- February 2017: started-up the Cabaça South East field of the East Hub Development Project, in Block 15/06 of the Angolan deep offshore, five months ahead of the schedule. Block 15/06 will reach a peak production of 150 KBBL/d this year.

- January 2017: successfully drilled an appraisal well of the Merakes gas discovery regulated by the Production Sharing Contract (PSC) in East Sepinggan, in Indonesia. This discovery is located 35 kilometers from the Eni operated Jangkrik field, close to starting operations.

-

January 2017: made a discovery in the PL128/128D licenses in the Norwegian Sea nearby the FPSO (Floating Production, Storage and Offloading) operating the Norne field. This discovery is part of Eni's near-field exploration strategy aimed at unlocking the presence of additional resources in proximity to existing infrastructures.

- January 2017: Eni was awarded three new exploration licenses in Norway, as a part of the APA Round.

TABLE OF CONTENTS

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 46 countries, including Italy, Libya, Egypt, Norway, the United Kingdom, Angola, Congo, Nigeria, the United States, Kazakhstan, Algeria, Australia, Venezuela, Iraq, Indonesia, Ghana and Mozambique. In 2017, Eni average daily production amounted to 1,719 KBOE/d on an available-for-sale basis. As of December 31, 2017, Eni's total proved reserves amounted to 6,990 mmBOE; proved reserves of subsidiaries totaled 6,430 mmBOE; Eni's share of reserves of equity-accounted entities was 560 mmBOE.

Eni's strategy in its Exploration & Production operations is to pursue profitable production growth by developing its portfolio of projects underway and by optimizing its current producing fields. We plan to achieve an average production growth rate of 3.5% in the next 2018-2021 four-year period. Our production plans are incorporating our Brent price scenario of 60$/BBL in 2018 and a gradual recovery in the subsequent years up to our long-term case of 72$/BBL in 2021 and going forwards (on constant monetary term compared to 2021, i.e. from 2022 onwards crude oil prices will grow in line with a projected inflationary rate); as well as certain other trading environment assumptions including an indication of Eni's production volume sensitivity to oil prices which are disclosed under "Item 5 – Management's expectations of operations".

Management plans to achieve the target production growth by continuing development activities and new project start-ups in the main areas of operations including, North Africa, Sub-Saharan Africa, Mexico, Middle and Far East, by leveraging Eni's vast knowledge of reservoirs and geological basins, as well as technical and producing synergies. New field start-ups, production ramp-ups and continuing production optimization will add approximately 900 KBOE/d in 2021; over 75% of these new projects have already been sanctioned and Eni is operator in approximately 80%.

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

Management plans to invest €24 billion to develop reserves over the next four years, of which approximately €16 billion directed to new field start-ups and ramp-ups while the remaining to product optimization.

Planned expenditures in exploration are expected to be approximately €2.0 billion. Our projects will comprise near-field activities designed to provide fast production support and contribute to the cash flow, as well as new initiatives targeting conventional prospects with high working interest in order to support Eni's dual exploration model in case of material discoveries. Finally, we forecast selective initiatives in high-risk, high-reward plays.

Management intends to implement a number of initiatives to support profitability in its upstream operations by exercising tight control over project time schedules and costs and reducing the time span, which is necessary to develop and market reserves. We plan to achieve efficient development of our reserves by: (i) in-sourcing critical engineering and project management activities and increasing direct control and governance on construction and commissioning activities; and (ii) signing framework agreements with major suppliers, using standardized specifications to speed up pre-award process for critical equipment and plants, increasing focus on supply chain programming to optimize order flows. Based on these initiatives, we believe that almost all of our projects, which we are currently developing over the next four years, will be completed on time and on budget.

TABLE OF CONTENTS

Finally, we plan to achieve further cost efficiencies by: (i) increasing the scale of our operations as we concentrate our resources on larger fields than in the past where we plan to achieve economies of scale; (ii) expanding the share of operated production. We believe operatorship will enable the Company to exercise better cost control, effectively manage reservoir and production operations, and deploy our safety standards and procedures to minimize risks; and (iii) applying our technologies which we believe can reduce drilling and completion costs.

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

For the year 2018, management plans to spend over €6 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&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&gas reserves are those quantities of liquids (including condensates and natural gas liquids) and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

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

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

Proved reserves to which Eni is entitled under concession contracts are determined by applying Eni's share of production to total proved reserves of the contractual area, in respect of the duration of the relevant mineral right. Proved reserves to which Eni is entitled under PSAs are calculated so that the sale of production entitlements should cover expenses incurred by the Group to develop a field (Cost Oil) and recognize the Profit Oil set contractually (Profit Oil). A similar scheme applies to buy-back and service contracts.

Reserves governance

Eni retains rigorous control over the process of booking proved reserves, through a centralized model of reserves governance. The Reserves Department of the Exploration & Production segment is in charge 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.

TABLE OF CONTENTS

Company guidelines have been reviewed by DeGolyer and MacNaughton (D&M), an independent petroleum engineering company, which has stated that those guidelines comply with the SEC rules1. D&M has also stated that the Company guidelines provide reasonable interpretation of facts and circumstances in line with generally accepted practices in the industry whenever SEC rules may be less precise. When participating in exploration and production activities operated by other entities, Eni estimates its share of proved reserves on the basis of the above guidelines.

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

The head of the Reserves Department attended the "Università degli Studi di Milano" and received a Master of Science degree in Physics in 1988. He has more than 25 years of experience in the oil&gas industry and more than 15 years of experience in evaluating reserves.

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

Reserves independent evaluation

Since 1991, Eni has requested qualified independent oil engineering companies to carry out an independent evaluation2 of part of its proved reserves on a rotational basis. The description of qualifications of the persons primarily responsible for the reserves audit is included in the third-party audit report3. In the preparation of their reports, independent evaluators rely upon information furnished by Eni, without independent verification, with respect to property interests, production, current costs of operations and development, sales agreements, prices and other factual information and data that were accepted as represented by the independent evaluators. These data, equally used by Eni in its internal process, include logs, directional surveys, core and PVT (Pressure Volume Temperature) analysis, maps, oil/gas/water production/injection data of wells, reservoir studies, technical analysis relevant to field performance, development plans, future capital and operating costs.

In order to calculate the net present value of Eni's equity reserves, actual prices applicable to hydrocarbon sales, price adjustments required by applicable contractual arrangements and other pertinent information are provided by Eni to third-party evaluators. In 2017, Ryder Scott Company and DeGolyer and MacNaughton provided an independent evaluation of approximately 29% of Eni's total proved reserves at December 31, 20174, confirming, as in previous years, the reasonableness of Eni internal evaluation5.

In the 2015-2017 three-year period, 96% of Eni total proved reserves were subject to an independent evaluation. As at December 31, 2017, the main Eni property, which did not undergo an independent evaluation in the last three years, was Blacktip (Australia).

1

See "Item 19 – Exhibits" in the Annual Report on Form 20-F 2009.

2

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

3

See "Item 19 – Exhibits".

4
Includes Eni's share of proved reserves of equity-accounted entities.

5
See "Item 19 – Exhibits".

TABLE OF CONTENTS

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, 2017, 2016 and 2015. Net proved reserves are set out in more detail under the heading “Supplemental oil and gas information” on page F-142.

HYDROCARBONS

(mmBOE)

	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total reserves
Consolidated subsidiaries1										
Year ended Dec. 31, 2017	422	525	1,052	1,078	1,436	1,150	427	203	137	6,430
developed	350	360	532	463	856	891	238	176	101	3,967
undeveloped	72	165	520	615	580	259	189	27	36	2,463
Year ended Dec. 31, 2016	354	426	1,139	1,293	1,317	1,221	491	227	145	6,613
developed	287	374	605	352	809	966	175	205	111	3,884
undeveloped	67	52	534	941	508	255	316	22	34	2,729
Year ended Dec. 31, 2015	465	495	1,694		1,282	1,198	422	269	150	5,975
developed	362	404	1,010		764	689	159	217	115	3,720
undeveloped	103	91	684		518	509	263	52	35	2,255
Equity-accounted entities										
Year ended Dec. 31, 2017			14		75		1		470	560
developed			14		20		1		359	394
undeveloped					55				111	166
Year ended Dec. 31, 2016			14		82		2	779		877
developed			14		26		2	349		391
undeveloped					56			430		486
Year ended Dec. 31, 2015			14		87		4	810		915
developed			14		22		2	265		303
undeveloped					65		2	545		612
Consolidated subsidiaries and equity accounted entities										
Year ended Dec. 31, 2017	422	525	1,066	1,078	1,511	1,150	428	203	607	6,990
developed	350	360	546	463	876	891	239	176	460	4,361

undeveloped	72	165	520	615	635	259	189	27	147	2,629
Year ended Dec. 31, 2016	354	426	1,153	1,293	1,399	1,221	493	1,006	145	7,490
developed	287	374	619	352	835	966	177	554	111	4,275
undeveloped	67	52	534	941	564	255	316	452	34	3,215
Year ended Dec. 31, 2015	465	495	1,708		1,369	1,198	426	1,079	150	6,890
developed	362	404	1,024		786	689	161	482	115	4,023
undeveloped	103	91	684		583	509	265	597	35	2,867

(1)
Include Eni's share of reserves held by a joint-operation in Mozambique which is proportionally consolidated in the Group consolidated financial statements in accordance to IFRS.

TABLE OF CONTENTS

LIQUIDS
(mmBBL)

	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total reserves
Consolidated subsidiaries										
Year ended Dec. 31, 2017	215	360	476	280	764	766	232	162	7	3,262
developed	169	219	306	203	546	547	81	144	5	2,220
undeveloped	46	141	170	77	218	219	151	18	2	1,042
Year ended Dec. 31, 2016	176	264	454	281	809	767	307	163	9	3,230
developed	132	228	287	205	507	556	124	143	8	2,190
undeveloped	44	36	167	76	302	211	183	20	1	1,040
Year ended Dec. 31, 2015	228	305	821		787	771	262	189	9	3,372
developed	171	237	542		511	355	126	149	9	2,100
undeveloped	57	68	279		276	416	136	40		1,272
Equity-accounted entities										
Year ended Dec. 31, 2017			12		12			136		160
developed			12		6			25		43
undeveloped					6			111		117
Year ended Dec. 31, 2016			13		15			140		168
developed			13		8			22		43
undeveloped					7			118		125
Year ended Dec. 31, 2015			13		16			158		187
developed			13		6			29		48
undeveloped					10			129		139
Consolidated subsidiaries and equity accounted entities										
Year ended Dec. 31, 2017	215	360	488	280	776	766	232	298	7	3,422
developed	169	219	318	203	552	547	81	169	5	2,263
undeveloped	46	141	170	77	224	219	151	129	2	1,159
Year ended Dec. 31, 2016	176	264	467	281	824	767	307	303	9	3,398

developed	132	228	300	205	515	556	124	165	8	2,233
undeveloped	44	36	167	76	309	211	183	138	1	1,165
Year ended Dec. 31, 2015	228	305	834		803	771	262	347	9	3,559
developed	171	237	555		517	355	126	178	9	2,148
undeveloped	57	68	279		286	416	136	169		1,411

NATURAL GAS
(BCF)

	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total reserves
Consolidated subsidiaries1										
Year ended Dec. 31, 2017	1,131	896	3,145	4,351	3,660	2,108	1,065	225	709	17,290
developed	987	771	1,233	1,421	1,693	1,878	862	171	519	9,535
undeveloped	144	125	1,912	2,930	1,967	230	203	54	190	7,755
Year ended Dec. 31, 2016	977	878	3,738	5,520	2,767	2,485	1,003	353	741	18,462
developed	845	801	1,732	799	1,651	2,239	280	338	559	9,244
undeveloped	132	77	2,006	4,721	1,116	246	723	15	182	9,218
Year ended Dec. 31, 2015	1,304	1,044	4,798		2,714	2,354	878	439	771	14,302
developed	1,051	919	2,566		1,390	1,830	185	373	585	8,899
undeveloped	253	125	2,232		1,324	524	693	66	186	5,403
Equity-accounted entities										
Year ended Dec. 31, 2017			14		349			1,819		2,182
developed			14		83			1,819		1,916
undeveloped					266					266
Year ended Dec. 31, 2016			15		368		4	3,484		3,871
developed			15		104		4	1,782		1,905
undeveloped					264			1,702		1,966
Year ended Dec. 31, 2015			13		387		12	3,581		3,993
developed			13		85		9	1,295		1,402
undeveloped					302		3	2,286		2,591
Consolidated subsidiaries and equity accounted entities										
Year ended Dec. 31, 2017	1,131	896	3,159	4,351	4,009	2,108	1,065	2,044	709	19,472
developed	987	771	1,247	1,421	1,776	1,878	862	1,990	519	11,451
undeveloped	144	125	1,912	2,930	2,233	230	203	54	190	8,021
Year ended Dec. 31, 2016	977	878	3,753	5,520	3,135	2,485	1,007	3,837	741	22,333

developed	845	801	1,747	799	1,755	2,239	284	2,120	559	11,149
undeveloped	132	77	2,006	4,721	1,380	246	723	1,717	182	11,184
Year ended Dec. 31, 2015	1,304	1,044	4,811		3,101	2,354	890	4,020	771	18,295
developed	1,051	919	2,579		1,475	1,830	194	1,668	585	10,301
undeveloped	253	125	2,232		1,626	524	696	2,352	186	7,994

(1)
Include Eni’s share of reserves held by a joint-operation in Mozambique which is proportionally consolidated in the Group consolidated financial statements in accordance to IFRS.

TABLE OF CONTENTS

Volumes of oil and natural gas applicable to long-term supply agreements with foreign governments in mineral assets where Eni is operator totaled 178 mmBOE as of December 31, 2017 (212 and 139 mmBOE as of December 31, 2016 and 2015, respectively). Said volumes are not included in reserves volumes shown in the table herein.

	Subsidiaries			Equity-accounted entities		
(mmBOE)	2017	2016	2015	2017	2016	2015
Additions to proved reserves	969	1,254	849	(285)	(10)	98
Purchases of minerals-in-place	2					
Sales of minerals-in-place	(523)		(17)			
Production for the year(a)	(631)	(616)	(629)	(32)	(28)	(13)

(a)
The difference compared to production sold of 622.3 mmBOE (642.4 mmBOE in 2015 and 608.6 mmBOE in 2016) reflected natural gas volumes of 35.2 mmBOE consumed in operations (26.4 mmBOE in 2015 and 32.1 mmBOE in 2016), changes in inventories and other factors.

	Subsidiaries and equity-accounted entities		
(%)	2017	2016	2015
Proved reserves replacement ratio of subsidiaries and equity-accounted entities, all sources	25	193	145
Proved reserves replacement ratio of subsidiaries and equity-accounted entities, organic	103	193	148

Eni's proved reserves as of December 31, 2017 totaled 6,990 mmBOE (liquids 3,422 mmBBL; natural gas 19,472 BCF). Eni's proved reserves reported a decrease of 500 mmBOE, or 6.7%, from December 31, 2016 due to production for the year, the disposal of a 40% interest in the Zohr gas field and of a 25% interest in the Coral discovery in Mozambique which obtained the FID in the year and the reclassification of 315 mmBOE of proved undeveloped reserves at the Perla gas project in Venezuela to the unproved category in accordance with the applicable US SEC regulation. These decreases were partly offset by the activity of the year. All sources additions to proved reserves booked in 2017 were 163 mmBOE; of which 448 mmBOE came from Eni's subsidiaries, while Eni's equity-accounted entities reported a negative revision due to the reserves reclassification in Venezuela described above.

Price effects were negligible, leading to a downward revision of 7 mmBOE, due to an increased Brent price used in the reserves estimation process up to 54.4 $/BBL in 2017 compared to 42.8 $/BBL in 2016. Further information about how to determine year-end amounts of proved reserves and the relevant net present value is provided in "Item 3 – Risk factors – Risks associated with the exploration and production of oil and natural gas".

The methods (or technologies) used in the Eni's proved reserves assessment in 2017 depend on stage of development, quality and completeness of data, and production history availability. The methods include volumetric estimates, analogies, reservoir modelling, decline curve analysis or a combination of such methods. The data considered for these analyses are obtained from a combination of reliable technologies that produce consistent and repeatable results including well or field measurements (i.e. logs, core samples, pressure information, fluid samples, production test data and performance data) and indirect measurements (i.e. seismic data). However for each reservoir assessment the most suitable combination of technologies and methods is applied providing a high degree of confidence in establishing reliable reserves estimates.

The all sources reserves replacement ratio achieved by Eni's subsidiaries and equity-accounted entities was 25% in 2017 (193% in 2016 and 145% in 2015) due to the Zohr and Mozambique disposals as well as the reclassification of PUD in Venezuela. The organic reserves replacement ratio was 103% (193% in 2016 and 148% in 2015) when excluding sales and purchases of minerals-in-place. The ratio increased to 151% when excluding the reclassification of PUD in Venezuela.

The all sources reserves replacement ratio was calculated by dividing additions to proved reserves including sales and purchases of mineral-in-place by total production, each as derived from the tables of

38

TABLE OF CONTENTS

changes in proved reserves prepared in accordance with FASB Extractive Activities – Oil & Gas (Topic 932) (see the supplemental oil and gas information in "Item 18 – Consolidated Financial Statements"). The reserves replacement ratio is a measure used by management to assess the extent to which produced reserves in the year are replaced by booked reserves total additions. Management considers the reserve replacement ratio to be an important indicator of the Company's ability to sustain its growth 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 infrastructures, reservoir performance, application of new technologies to improve the recovery factor as well as changes in oil&gas prices, political risks and geological and environmental risks. See "Item 3 – Risks associated with the exploration and production of oil and natural gas –Uncertainties in estimates of oil and natural gas reserves".

The average reserves life index of Eni's proved reserves was 10.5 years as of December 31, 2017, which included reserves of both subsidiaries and equity-accounted entities.

Eni's subsidiaries

Eni's subsidiaries added 448 mmBOE of proved oil&gas reserves in 2017 net of sales and purchase of minerals-in-place. This comprised 336 mmBBL of liquids and 611 BCF of natural gas. The breakdown of additions to proved reserves is the following: (i) extensions and discoveries were up by 483 mmBOE mainly due to the final investment decisions made for the Coral project offshore Mozambique and the Johan Castberg project offshore Norway; (ii) revisions of previous estimates were up by 466 mmBOE and mainly derived from progress in development activities at the number of projects including Zohr in Egypt, Jangkrik in Indonesia and Kashagan in Kazakhstan; (iii) improved recovery were 20 mmBOE mainly reported in Iraq and Egypt; (iv) purchases of mineral-in-place referred to certain assets in Nigeria; and (v) sales of minerals-in-place referred to the disposal of a 25% interest in natural gas-rich Area 4 offshore Mozambique and the divestment of a 40% stake in the Zohr gas field offshore in Egypt. Further information is provided in "Oil and gas properties, operations and acreage" in Eni's principal oil and gas activities described in Mozambique and Egypt, respectively.

Eni's share of equity-accounted entities

Additions in Eni's share of equity-accounted entities' proved oil&gas were negative in 2017 and derived mainly from the reclassification of 315 mmBOE of proved undeveloped reserves at the Perla gas project in Venezuela to the unproved category in accordance with the applicable US SEC regulation.

Proved undeveloped reserves

Proved undeveloped reserves as of December 31, 2017 totaled 2,629 mmBOE. At year-end, proved undeveloped reserves of liquids amounted to 1,159 mmBBL, mainly concentrated in Africa and Asia. Proved undeveloped reserves of natural gas amounted to 8,021 BCF, mainly located in Africa. Proved undeveloped reserves of consolidated subsidiaries amounted to 1,042 mmBBL of liquids and 7,755 BCF of natural gas. The table below provide a summary of changes in total proved undeveloped reserves for 2017.

(mmBOE)	Subsidiaries and equity-accounted entities
Proved undeveloped reserves as of December 31, 2016	3,215
Reclassification to proved developed reserves	(489)
Reclassification of the Perla Phase 2 project reserves	(315)
Extensions and discoveries	483
Revisions of previous estimates	240
Improved recovery	18
Sales of minerals-in-place	(523)
Proved undeveloped reserves as of December 31, 2017	2,629

In 2017, total proved undeveloped reserves decreased by 586 mmBOE mainly due to: (i) progress in maturing PUD to proved developed (489 mmBOE); (ii) extensions and discoveries (up by 483 mmBOE) due to the final investment decision made for the Coral project offshore Mozambique and the Johan Castberg project offshore Norway; (iii) reclassification of 315 mmBOE of proved undeveloped reserves at the Perla gas project in Venezuela to the unproved category in accordance with the applicable US SEC regulation; (iv) revisions of previous estimates (up by 240 mmBOE) mainly reported in Egypt due to the development activity of the Zohr project; (v) improved recovery (up 18 mmBOE) in particular in Iraq and Egypt; and (vi) divestments (down by 523 mmBOE) related to the disposals of interests in properties in Mozambique and Egypt, as above-mentioned.

During 2017, Eni converted 489 mmBOE of proved undeveloped reserves to proved developed reserves due to the progress of the development activities, production start-ups and project revisions. The main reclassifications to proved developed reserves are related to the following fields/projects: Zohr (Egypt), Jangkrik (Indonesia); Cabaca South East (Angola), Sankofa (Ghana) and Nené (Congo).

In 2017, capital expenditures amounted to approximately €7.1 billion and was made to progress the development of proved undeveloped reserves.

Reserves that remain proved undeveloped for five or more years are a result of several factors that affect the timing of the projects development and execution, such as the complex nature of the development project in adverse and remote locations, physical limitations of infrastructures or plant capacity and contractual limitations that establish production levels. The Company estimates that approximately 1 BBOE of proved undeveloped reserves have remained undeveloped for five years or more at the balance sheet date, mainly related to: (i) the Kashagan project in Kazakhstan (0.2 BBOE), related to forthcoming development phases (for further information see "Item 4 – Oil and gas properties, operations and acreage – Kashagan"); (ii) the Zubair field in Iraq (0.2 BBOE). Zubair is an infrastructure-driven large-scale project, where development of PUDs has been conditioned by the completion of such infrastructures. The large part of the planned expenditures for such project has already been made by Eni and the installation of the production facilities required to achieve and maintain the full field production plateau of 700 KBBL/d is almost complete. Eni's planned activities contemplate the drilling of additional production and injection wells to be linked to the facilities currently in place; (iii) the Junin 5 field in Venezuela (0.1 BBOE) where the development scheme is planned through execution of several optimization activities with low technical complexity; and (iv) certain Libyan gas fields (0.5 BBOE) where development completion and production start-ups are planned according to the delivery obligations set forth in a long-term gas supply agreement currently in force. In order to secure fulfillment of the contractual delivery quantities, Eni will implement phased production start-up from the relevant fields which are expected to be put in production over the next several years. (See also our discussion under the "Risk factors" section about risks associated with oil and gas development projects).

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

Delivery commitments

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

Eni is contractually committed under existing contracts or agreements to deliver in the next three years mainly natural gas to third parties for a total of approximately 534 mmBOE from producing assets located mainly in Algeria, Australia, Egypt, Indonesia, Libya, Nigeria, Norway and Venezuela.

The sales contracts contain a mix of fixed and variable pricing formulas that are generally indexed 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 is expected to account for approximately 88% of delivery commitments.

Eni has met all contractual delivery commitments as of December 31, 2017.

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

TABLE OF CONTENTS

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 2017, oil and natural gas production available for sale averaged 1,719 KBOE/d (1,671 KBOE/d in 2016) and increased by 2.9% from 2016, mainly due to new project start-ups and the ramp-ups at fields started up in 2016, mainly in Angola, Egypt, Ghana, Indonesia and Kazakhstan as well as by the restart of certain Libyan fields due to better safety conditions. These positive results were partly offset by OPEC production cuts, negative price effects at PSAs contracts and lower production as a result of planned and unplanned shutdowns in Norway, the United Kingdom and the Gulf of Mexico, as well as mature field declines. New field start-ups and ramp-ups of production added an estimated 243 KBOE/d of new production.

Liquids production (852 KBBL/d) decreased by 26 KBBL/d, or 3% from the full year of 2016. Price effect, OPEC cuts and shutdowns in Norway, the United Kingdom and the Gulf of Mexico were partly offset by start-ups and ramp-ups of the year mainly in Angola, Ghana and Kazakhstan as well as higher production in Libya.

Natural gas production (4,734 mmCF/d) increased by 405 mmCF/d, or 9.4% compared to the full year of 2016. Start-ups and ramp-ups of producing assets in Indonesia and Egypt and the increasing production in Libya were partly offset by shutdowns, mature fields decline and price effect.

Oil and gas production sold amounted to 622.3 mmBOE. The 4.7 mmBOE difference over production on available-for-sale basis (627 mmBOE in 2017) reflected mainly changes in inventory and other factors.

Approximately 70% of liquids production sold (308.3 mmBBL) was destined to Eni's mid-downstream sectors. About 20% of natural gas production sold (1,713 BCF) was destined to Eni's Gas & Power segment.

The tables below provide Eni subsidiaries and its equity-accounted entities' production (annual volumes and daily averages), by final product marketed of liquids and natural gas by geographical area of each of the last three fiscal years.

2017 Production available for sale (a)		Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania
Hydrocarbons production										
Eni consolidated subsidiaries	(KBOE/d)	127	183	457	216	305	126	105	96	21
	(mmBOE)	46	67	167	79	111	46	38	35	8
Eni share of equity-accounted entities	(KBOE/d)			3		17		2	61	
	(mmBOE)			1		6		1	22	
Liquids production										
Eni consolidated subsidiaries	(KBBL/d)	53	102	159	72	246	83	53	63	2
	(mmBBL)	19	37	58	26	90	30	20	23	1
Eni share of equity-accounted entities	(KBBL/d)			3		3		1	12	
	(mmBBL)			1		2			4	

Natural gas production										
Eni consolidated subsidiaries	(mmCF/d)	402	443	1,632	784	328	231	282	181	101
	(BCF)	147	162	596	286	119	84	103	66	37
Eni share of equity-accounted entities	(mmCF/d)			2		72		9	267	
	(BCF)			1		27		3	97	

(a)
It excludes production volumes of natural gas consumed in operations. Said volumes were 527 mmCF/d or 35.2 mmBOE.

41

TABLE OF CONTENTS

2016 Production available for sale (a)		Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania
Hydrocarbons production										
Eni consolidated subsidiaries	(KBOE/d)	127	195	438	170	312	107	114	114	23
	(mmBOE)	47	71	160	62	114	39	42	42	8
Eni share of equity-accounted entities	(KBOE/d)			3		4		4	60	
	(mmBOE)			1		2		2	22	
Liquids production										
Eni consolidated subsidiaries	(KBBL/d)	47	109	165	76	247	65	78	69	3
	(mmBBL)	17	40	60	28	91	24	28	25	1
Eni share of equity-accounted entities	(KBBL/d)			3		1		1	14	
	(mmBBL)			1				1	5	
Natural gas production										
Eni consolidated subsidiaries	(mmCF/d)	436	468	1,486	514	353	234	199	243	110
	(BCF)	159	171	544	188	129	86	73	89	40
Eni share of equity-accounted entities	(mmCF/d)			3		16		15	252	
	(BCF)			1		6		6	92	

(a)
It excludes production volumes of natural gas consumed in operations. Said volumes were 478 mmCF/d or 32.1 mmBOE.

2015 Production available for sale (a)		Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania
Hydrocarbons production										
Eni consolidated subsidiaries	(KBOE/d)	161	179	631		324	92	123	120	25
	(mmBOE)	59	65	230		119	33	45	44	9
	(KBOE/d)			4				5	24	

Eni share of equity-accounted entities									
	(mmBOE)			1			2	9	
Liquids production									
Eni consolidated subsidiaries	(KBBL/d)	69	85	268	256	56	77	75	5
	(mmBBL)	25	31	98	93	20	28	28	2
Eni share of equity-accounted entities	(KBBL/d)			4			1	12	
	(mmBBL)			1			1	4	
Natural gas production									
Eni consolidated subsidiaries	(mmCF/d)	503	515	1,990	378	199	259	243	107
	(BCF)	183	188	727	138	73	94	89	39
Eni share of equity-accounted entities	(mmCF/d)			3			19	68	
	(BCF)			1			7	25	

(a)
It excludes production volumes of natural gas consumed in operations. Said volumes were 397 mmCF/d or 26.4 mmBOE.

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 55 KBOE/d, 56 KBOE/d and 84 KBOE/d in 2017, 2016 and 2015, respectively.

TABLE OF CONTENTS

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

AVERAGE SALES PRICES AND PRODUCTION COST PER UNIT OF PRODUCTION

($)	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2015										
Consolidated subsidiaries										
Oil and condensates, per BBL	43.46	45.88	46.66		49.91	48.26	40.10	43.36	45.84	46.46
Natural gas, per KCF	6.92	6.30	4.69		1.49	0.47	4.83	2.20	5.07	4.54
Average production cost, per BOE	11.08	10.93	5.72		14.08	7.93	6.48	11.61	14.49	9.18
Equity-accounted entities										
Oil and condensates, per BBL			18.03				27.89	38.18		35.15
Natural gas, per KCF			3.78				9.27	4.24		5.30
Average production cost, per BOE			8.98				8.67	16.48		14.51
2016										
Consolidated subsidiaries										
Oil and condensates, per BBL	33.19	39.97	42.37	33.05	41.92	39.61	36.89	34.86	37.96	39.33
Natural gas, per KCF	4.93	4.49	3.10	3.82	1.41	0.34	3.50	1.94	3.60	3.20
Average production cost, per BOE	9.69	9.31	4.33	6.34	12.09	7.58	6.14	8.70	7.08	7.79
Equity-accounted entities										
Oil and condensates, per BBL			17.93				34.95	32.39		30.85
			1.85				5.92	4.17		4.25

Natural gas, per KCF										
Average production cost, per BOE			9.74				8.19	8.81		8.34
2017										
Consolidated subsidiaries										
Oil and condensates, per BBL	46.51	47.81	52.68	46.06	53.66	50.62	48.94	44.24	49.36	50.33
Natural gas, per KCF	6.45	5.81	2.96	4.19	1.87	0.58	3.75	2.35	4.05	3.62
Average production cost, per BOE	11.43	11.62	4.76	4.51	13.34	9.78	6.39	10.10	7.77	8.45
Equity-accounted entities										
Oil and condensates, per BBL			45.39		38.34		44.43	41.49		38.65
Natural gas, per KCF			2.63		7.34		6.06	4.19		4.64
Average production cost, per BOE			10.30		8.05		11.64	9.52		9.31

Development activities

In 2017, a total of 178 development wells were drilled (90.7 of which represented Eni's share) as compared to 296 development wells drilled in 2016 (118.7 of which represented Eni's share) and 335 development wells drilled in 2015 (132.4 of which represented Eni's share).

The decrease in the number of development wells year-on-year reflects the finalization of certain large projects in 2016, which started production in 2017.

The drilling of 49 development wells (22.9 of which represented Eni's share) is currently underway.

TABLE OF CONTENTS

The table below summarizes the number of the Company's net interest in productive and dry development wells completed in each of the past three years and the status of the Company's development wells in the process of being drilled as of December 31, 2017. A dry well is one found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Development Well Activity

	Net wells completed						Wells in progress at 31 Dec.	
	2017		2016		2015		2017	
(units)	Productive	Dry	Productive	Dry	Productive	Dry	Gross	Net
Italy	2.6		4.0		6.0		1.0	1.0
Rest of Europe	2.7	0.2	5.6		10.2	0.1	5.0	0.8
North Africa	5.1		6.2	0.7	30.5	2.8	10.0	5.5
Egypt	49.7	2.3	32.4	0.5			10.0	5.4
Sub-Saharan Africa	8.6		21.2	0.2	22.0	2.5	21.0	9.6
Kazakhstan	1.2		4.6		4.7		2.0	0.6
Rest of Asia	15.0	0.2	31.6	0.5	29.7	5.9		
Americas	3.1		9.9	1.3	17.4	0.1		
Australia and Oceania					0.5			
Total including equity-accounted entities	88.0	2.7	115.5	3.2	121.0	11.4	49.0	22.9

Exploration activities

In 2017, a total of 25 new exploratory wells were drilled (15.9 of which represented Eni's share), as compared to 16 exploratory wells drilled in 2016 (10.2 of which represented Eni's share) and 29 exploratory wells drilled in 2015 (19.1 of which represented Eni's share).

The overall commercial success rate was 60% (52% net to Eni) as compared to 50% (50% net to Eni) and 16.7% (25.1% net to Eni) in 2016 and 2015, respectively.

The following table summarizes the Company's net interests in productive and dry exploratory wells completed in each of the last three fiscal years and the number of exploratory wells in the process of being drilled and evaluated as of December 31, 2017. A dry well is one found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

	Net wells completed						Wells in progress at Dec. 31(1)	
	2017		2016		2015		2017	
(units)	Productive	Dry	Productive	Dry	Productive	Dry	Gross	Net
Italy				1.0			4.0	2.3
Rest of Europe	1.2	1.3	0.1	0.4		2.2	9.0	2.5
North Africa	0.5		0.5	1.0	3.3	5.8	7.0	6.5
Egypt	2.5	5.4	5.5	0.8			7.0	4.9
Sub-Saharan Africa	2.9	0.3	0.1	1.1	0.6	2.9	28.0	14.1
Kazakhstan							6.0	1.1
Rest of Asia				0.9		3.4	11.0	5.0

Americas	0.5					1.0	1.0		0.3	5.0	4.5
Australia and Oceania										1.0	0.3
Total including equity-accounted entities	7.6		7.0	6.2		6.2	4.9		14.6	78.0	41.2

(1)
Includes temporary suspended wells pending further evaluation.

Oil and gas properties, operations and acreage

In 2017, Eni performed its operations in 46 countries located in five continents. As of December 31, 2017, Eni’s mineral right portfolio consisted of 756 exclusive or shared rights of exploration and development activities for a total acreage of 414,918 square kilometers net to Eni (323,896 square kilometers net to Eni as of December 31, 2016). Developed acreage was 31,038 square kilometers and undeveloped acreage was 383,880 square kilometers net to Eni. In 2017, changes in total net acreage mainly derived from: (i) new leases mainly in Cyprus, Ivory Coast, Kazakhstan, Morocco, Mexico and Oman for a total acreage of approximately 97,200 square kilometers; (ii) the total relinquishment of licences mainly in Kenya, Pakistan, Ukraine, Norway, the

44

TABLE OF CONTENTS

United Kingdom, Egypt and the United States covering an acreage of approximately 6,700 square kilometers; (iii) interest increase mainly in Kenya and Australia for a total acreage of approximately 6,800 square kilometers; (iv) partial relinquishment in Indonesia, Gabon, Egypt and Pakistan or interest reduction mainly in Mozambique and Egypt for approximately 6,300 square kilometers.

The table below provides certain information about the Company's oil&gas properties. It provides the total gross and net developed and undeveloped oil and natural gas acreage in which the Group and its equity-accounted entities had interest as of December 31, 2017. A gross acreage is one in which Eni owns a working interest.

	December 31, 2016	December 31, 2017						
	Total net acreage (a)	Number of interests	Gross developed acreage (a) (b)	Gross undeveloped acreage (a)	Total gross acreage (a)	Net developed acreage (a) (b)	Net undeveloped acreage (a)	Total net acreage (a)
EUROPE	45,380	280	15,232	59,373	74,605	10,414	40,792	51,206
Italy	16,767	144	10,011	10,321	20,332	8,351	8,029	16,380
Rest of Europe	28,613	136	5,221	49,052	54,273	2,063	32,763	34,826
Cyprus	10,018	6		23,858	23,858		17,967	17,967
Croatia	987	2	1,975		1,975	987		987
Greenland	1,909	2		4,890	4,890		1,909	1,909
Montenegro	614	1		1,228	1,228		614	614
Norway	2,608	54	2,337	4,403	6,740	462	1,655	2,117
Portugal	3,182	3		4,547	4,547		3,182	3,182
United Kingdom	6,328	60	909	5,298	6,207	614	5,191	5,805
Other Countries	2,967	8		4,828	4,828		2,245	2,245
AFRICA	152,676	264	46,319	260,611	306,930	11,723	150,258	161,981
North Africa	18,727	65	8,735	38,707	47,442	3,626	22,171	25,797
Algeria	1,179	42	3,172	187	3,359	1,110	31	1,141
Libya	13,294	11	1,963	24,673	26,636	958	12,336	13,294
Morocco	2,696	2		13,847	13,847		9,804	9,804
Tunisia	1,558	10	3,600		3,600	1,558		1,558
Egypt	10,665	54	5,692	19,683	25,375	2,131	7,061	9,192
Sub-Saharan Africa	123,284	145	31,892	202,221	234,113	5,966	121,026	126,992
Angola	4,367	58	8,098	12,953	21,051	1,027	3,340	4,367
Congo	1,168	25	1,430	1,320	2,750	843	628	1,471
Gabon	6,217	4		5,283	5,283		5,283	5,283
Ghana	579	3	226	1,127	1,353	100	479	579
Ivory Coast	286	3		4,010	4,010		2,905	2,905
Kenya	41,173	6		50,677	50,677		43,948	43,948
Liberia	585	1		2,341	2,341		585	585

Mozambique	1,956	6		3,911	3,911		978	978
Nigeria	7,370	34	22,138	8,631	30,769	3,996	3,374	7,370
South Africa	26,279	1		65,505	65,505		26,202	26,202
Other Countries	33,304	4		46,463	46,463		33,304	33,304
ASIA	109,761	60	14,560	286,866	301,426	5,058	178,971	184,029
Kazakhstan	869	7	2,391	3,890	6,281	442	1,101	1,543
Rest of Asia	108,892	53	12,169	282,976	295,145	4,616	177,870	182,486
China	7,069	8	77	7,141	7,218	13	7,141	7,154
India	5,244	1		13,110	13,110		5,244	5,244
Indonesia	25,181	14	4,949	26,892	31,841	1,990	20,899	22,889
Iraq	446	1	1,074		1,074	446		446
Myanmar	13,558	4		24,080	24,080		13,558	13,558
Oman		1		90,760	90,760		77,146	77,146
Pakistan	8,746	13	5,869	11,486	17,355	1,987	5,414	7,401
Russia	20,862	3		62,592	62,592		20,862	20,862
Timor Leste	1,230	1		1,538	1,538		1,230	1,230
Turkmenistan	180	1	200		200	180		180
Vietnam	23,132	5		30,777	30,777		23,132	23,132
Other Countries	3,244	1		14,600	14,600		3,244	3,244
AMERICAS	5,696	139	4,854	9,626	14,480	3,134	3,507	6,641
Ecuador	1,985	1	1,985		1,985	1,985		1,985
Mexico	67	6		1,657	1,657		1,146	1,146
Trinidad & Tobago	66	1	382		382	66		66
United States	1,186	117	1,226	879	2,105	586	466	1,052
Venezuela	1,066	6	1,261	1,543	2,804	497	569	1,066
Other Countries	1,326	8		5,547	5,547		1,326	1,326
AUSTRALIA AND OCEANIA	10,383	13	1,140	15,567	16,707	709	10,352	11,061
Australia	10,383	13	1,140	15,567	16,707	709	10,352	11,061
Total	323,896	756	82,105	632,043	714,148	31,038	383,880	414,918

(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.

TABLE OF CONTENTS

The table below provides the number of gross and net productive oil and natural gas wells in which the Group companies and its equity-accounted entities had an interest as of December 31, 2017. 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 borehole 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 9,147 (3,725.5 of which represent Eni's share).

Productive oil and gas wells at Dec. 31, 2017(a)

(units)	Oil Wells		Natural gas Wells	
	Gross	Net	Gross	Net
Italy	231.0	184.7	573.0	495.7
Rest of Europe	378.0	65.0	177.0	92.2
North Africa	687.0	284.5	90.0	48.9
Egypt	1,186.0	729.4	139.0	46.8
Sub-Saharan Africa	2,786.0	585.7	330.0	29.1
Kazakhstan	205.0	55.6		
Rest of Asia	739.0	477.5	1,032.0	402.0
Americas	273.0	134.1	296.0	86.7
Australia and Oceania	7.0	3.8	18.0	3.8
Total including equity-accounted entities	6,492.0	2,520.3	2,655.0	1,205.2

(a)
Multiple completion wells included above: approximately 1,960 (716.2 net to Eni).

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

Italy

Eni has been operating in Italy since 1926. In 2017, Eni's oil and gas production amounted to 127 KBOE/d. Eni's activities in Italy are deployed in the Adriatic and Ionian Seas, 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 (50 operated onshore and 62 operated offshore) and exploration licenses (13 onshore and 9 offshore).

TABLE OF CONTENTS

The Adriatic and Ionian Sea represents Eni's main production area, accounting for 48% of Eni's domestic production in 2017. Main operated fields are Barbara, Cervia/Arianna, Annamaria, Luna, Angela, Hera Lacinia and Bonaccia. Development activities in the Adriatic offshore concerned maintenance and production optimization, mainly at the Barbara and Porto Garibaldi-Agostino fields.

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, which accounts for 38% of Eni's domestic production, is treated by the Val d'Agri oil center ("COVA").

On April 18, 2017, Eni, before receiving a request by the Italian Authorities to halt operations, decided to shut-down the COVA due to the detection of an oil spill in the area adjoining the plant. Management promptly executed all requested remedial measures. On July 18 2017, Eni restarted operations at the COVA following approvals of the relevant Authorities that tested the functionality of the plant and the presence of all necessary environmental and safety conditions. Further information on this matter is provided Item 19 – consolidated financial statement – footnote 38-Legal proceedings".

Eni operates 12 production concessions onshore and 3 offshore in Sicily. The main fields are Gela, Tresauro, Giaurone, Fiumetto, Prezioso and Bronte, which in 2017 accounted for approximately 8% of Eni's production in Italy.

Rest of Europe

Eni's operations in the Rest of Europe are mainly conducted in Croatia, Norway and the UK. In 2017, the Rest of Europe accounted for 11% of Eni's total worldwide production of oil and natural gas.

Croatia. Eni has been present in Croatia since 1996. In 2017, Eni's production of natural gas averaged approximately 16 mmCF/d. Activities are deployed in the Adriatic Sea near the city of Pula.

Exploration and production activities in Croatia are regulated by PSAs.

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

TABLE OF CONTENTS

Norway. Eni has been operating in Norway since 1965. Eni's activities are performed in the Norwegian Sea, in the Norwegian section of the North Sea and in the Barents Sea. Eni's production in Norway amounted to 126 KBOE/d in 2017.

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

Eni currently holds interests in 10 production areas in the Norwegian Sea. The principal producing fields are Åsgard (Eni's interest 14.82%), Kristin (Eni's interest 8.25%), Heidrun (Eni's interest 5.17%), Mikkel (Eni's interest 14.9%), Tyrihans (Eni's interest 6.2%), Marulk (Eni operator with a 20% interest) and Morvin (Eni's interest 30%) which in 2017 accounted for 57% of Eni's production in Norway.

Eni holds interests in 2 production licenses in the Norwegian section of the North Sea. The main producing properties is the Great Ekofisk Area (Eni's interest 12.39%) in PL 018, which includes the Ekofisk field and the Eldfisk and Embla satellites fields. In 2017, the Great Ekofisk Area produced approximately 23 KBOE/d net to Eni and accounted for approximately 18% of Eni's production in Norway. The license expires in 2028, and negotiations are ongoing to grant an extension.

Eni holds interests in 13 exploration and development licences in the Barents Sea, of which Eni operates 8 licences. Operations have been focused on the Goliat production fields in PL 229 (Eni operator with a 65% interest). In 2017, Goliat produced 28 KBOE/d or 22% of Eni's production in Norway. The license expires in 2042.

Development activities mainly concerned: (i) the drilling and production start-up of two new injection wells and an additional production well of the Goliat field; and (ii) infilling activities to support production of the Ekofisk, Eldfisk,

Heidrun, Asgard and Norne (Eni’s interest 6.9%) fields.
The final investment decision of the Johan Castberg field (Eni’s interest 30%) was sanctioned. The project is located in the Barents Sea and start-up is expected in 2022.
Exploration activities yielded positive results with: (i) the Cape Vulture oil and gas discovery in the PL128/128D license (Eni’s interest 11.5%) in the Norwegian Sea, nearby to the production facilities of the Norne field; and (ii) the Kayak oil discovery in the PL532 license (Eni’s interest 30%) in the Barents Sea. The well is located nearby to the Johan Castberg developing project in the area.

TABLE OF CONTENTS

United Kingdom. Eni has been present in the UK since 1964. Eni's activities are carried out in the British section of the North Sea and the Irish Sea. In 2017, Eni's net production of oil and gas averaged 54 KBOE/d. Exploration and production activities in the UK are regulated by concession contracts.

Eni currently holds interests in 4 production areas of which the Liverpool Bay is operated by Eni with a 100% interest and Hewett Area is operated with an 89.3% interest. The other non-operated fields are Elgin/Franklin (Eni's interest 21.87%), Glenelg (Eni's interest 8%), J Block and Jasmine (Eni's interest 33%) as well as Jade (Eni's interest 7%).

Eni holds interest in 14 exploration licences of which Eni operates 10 licenses, with interest ranging from 9% to 100%.

North Africa

Eni's operations in North Africa are conducted in Algeria, Libya, Morocco and Tunisia. In 2017, North Africa accounted for 27% of Eni's total worldwide production of oil and natural gas.

Algeria. Eni has been present in Algeria since 1981. In 2017, Eni's oil&gas production averaged 75 KBOE/d.

Operated activities are located in the Bir Rebaa desert, in the Central-Eastern area of the country: (i) blocks 403a/d (Eni's interest from 65% to 100%); (ii) block ROM North (Eni's interest 35%); (iii) blocks 401a/402a (Eni's interest 55%); (iv) block 403 (Eni's interest 50%); (v) block 405b (Eni's interest 75%); and (vi) block 212 (Eni's interest 22.38%) with discoveries already made. In addition, Eni holds interest in the non-operated block 404 and block 208 with a 12.25% stake.
Exploration and production activities in Algeria are regulated by Production Sharing Agreements (PSAs) and concession contracts.
Production in blocks 403a/d and ROM North comes mainly from the HBN and ROM and satellites fields and represented approximately 21% of Eni's production in Algeria in 2017.
Production in blocks 401a/402a comes mainly from the ROD/SFNE and satellites fields and accounted for approximately 17% of Eni's production in Algeria in 2017.

TABLE OF CONTENTS

The main fields in block 403 are BRN, BRW and BRSW, which accounted for approximately 9% of Eni's production in Algeria in 2017. In June 2017, Eni signed with the relevant Authorities a 15-year extension agreement of the Block 403 fields, with a possible further 10-year extension. The agreement received all the necessary authorizations required by the country.

The main fields in block 404 are HBN and HBNS and satellites, which accounted for approximately 22% of Eni's production in Algeria in 2017.

Production in block 405b comes mainly from MLE and CAFC projects and accounted for approximately 15% of Eni's production in the country.

The El-Merk field is the main production project in the Block 208 and accounted for approximately 16% of Eni's production in Algeria in 2017.

Development activities concerned: (i) infilling activities and production optimization at the Zea field in the Block 403 a/d and at the ROD and SF/SFNE fields in the Blocks 401a/402a; (ii) workover activities at the BRN, BRW and RSW fields in the Block 403 and HBNS, HBNN and Ourhoud fields in the Block 404; (iii) in the Block 405b the completion of the treatment plant with a capacity of 32 KBBL/d of the CAFC oil project, the ongoing drilling planned activities in the area as well as infilling activities at the MLE project; and (iv) the ongoing development activities of the El Merk field in the Block 208 with the drilling of production and water injection wells.

In December 2017, Eni and Sonatrach the state oil company signed a Memorandum of Understanding for the development project in the renewables sector. The agreement includes the feasibility studies to build solar power production units in the selected production areas operated by the state company.

Libya. Eni started operations in Libya in 1959.

In recent years, Eni's production levels in Libya were negatively impacted by the country's political instability. More recently, Eni's oil activities in the country have improved, reflecting a certain degree of normalization in the Country internal situation and improving security conditions. In 2017, Eni's production in Libya was 377 KBOE/d, which represents the highest level of Eni's production in the Country. Despite this and other positive developments, Libya's geopolitical situation continues to represent a source of risk and uncertainty for the foreseeable future. For further information on this matter, see "Item 3 – Risk factors-Political considerations"

Production activity is carried out in the Mediterranean Sea near Tripoli and in the Libyan Desert area and includes six contract areas. Onshore contract areas are: (i) Area A consisting in the former concession 82 (Eni's interest 50%); (ii) Area B, former concessions 100 (Bu Attifel field) and the NC 125 Block (Eni's interest 50%); (iii) Area E with El Feel (Elephant) field (Eni's interest 33.3%); (iv) Area F with Block 118 (Eni's interest 50%) and (v) Area D with Block NC 169 that feeds the Western Libyan Gas Project (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 Block NC 41 that feeds the Western Libyan Gas Project.
In the exploration phase, Eni is operator in the onshore contract Areas A, B and offshore Area D.

TABLE OF CONTENTS

Exploration and production activities in Libya are regulated by six Exploration and Production Sharing Agreement contracts (EPSA). The licenses of Eni's assets in Libya expire in 2042 and 2047 for oil&gas properties, respectively.
Development activities concerned: (i) the installation, commissioning and production start-up of a new FSO at the Bouri field; (ii) the second development phase of the Bahr Essalam field (Eni's interest 50%) with the installation of the offshore facilities and the completion of wells. The development plan foresees drilling and completion of ten production wells. Start-up is expected in 2018; and (iii) the drilling and linkage of two additional production wells at the Wafa field (Eni's interest 50%). The upgrading activities of the compression capacity of Wafa plant progressed to support natural gas production. Start-up is expected in 2018.
Exploration activity yielded positive results with a new gas and condensates discovery in the contractual area D. The discovery is located nearby to the Bouri and Bahr Essalam production fields. In April 2017, the Country's authorities extended the exploration license period until 2019, without additional commitment activities.
Management expect to reduce the Company's exposure to Libya over the plan period as a result of the slowdown in exploration and development activities in recent years due to an uncertain political outlook.
Morocco. In December 2017, Eni signed a Petroleum Agreement with the Moroccan State Company ONHYM that includes the operatorship to Eni and a 75% stake enter into Tarfaya Offshore Shallow exploration permits I-XII, located in the Atlantic Ocean offshore. The agreement is subject to approval by the relevant Authorities of the country.
In June 2017, Eni signed an agreement with the ONHYM Company for exploration activities in the El Jadida Offshore area.
Eni also operates with a 40% interest the Rabat Deep Offshore exploration permits I-VI offshore, following a Farm-Out Agreement (FOA) with Chariot Oil & Gas defined in 2016.
Tunisia. Eni has been present in Tunisia since 1961. In 2017, Eni's production amounted to 8 KBOE/d.
Eni's activities are located mainly in the Southern Desert areas and in the Mediterranean offshore facing Hammamet. Exploration and production in this country are regulated by concessions.
Production mainly comes from operated Maamoura and Baraka offshore blocks (Eni's interest 49%) and the Adam (Eni operator with a 25% interest), Oued Zar (Eni operator with a 50% interest), Djebel Grouz (Eni operator with a 50% interest), MLD (Eni's interest 50%) and El Borma (Eni's interest 50%) onshore blocks.

TABLE OF CONTENTS

Egypt

Eni has been present in Egypt since 1954. Exploration and production activities in Egypt are regulated by Production Sharing Agreements.

In 2017, Eni's share of production in this country amounted to 216 KBOE/d and accounted for 13% of Eni's total annual hydrocarbon production. Eni's main producing liquid fields are located in the Gulf of Suez, primarily the Belayim field (Eni's interest 100%), and in the Western Desert mainly the Melehia (Eni's interest 76%), the Ras Qattara (Eni's interest 75%), Raml (Eni's interest 45%) and West Razzaq and Kanayis (Eni's interest 100%) concessions. Gas production mainly comes from the operated or participated concession of North Port Said (Eni's interest 100%), El Temsah (Eni's interest 50%), Baltim (Eni's interest 50%), Ras el Barr (Eni's interest 50%, non-operated) and the Nile Delta (Eni's interest 75%), located offshore the Nile Delta. In 2017, production from these large concessions accounted for approximately 95% of Eni's production in Egypt.

Eni operates the Shoruk concession (Eni's interest 60%) where the Zohr gas field is located. Management believes that this field contains a large amount of gas reserves. The concession expires in 2037. Production at the field started at the end of 2017.

In 2017, Eni closed two agreements with major international players in the oil&gas business for the disposal of a 40% interest in the Zohr field, as part of its dual exploration model that targets early monetization of the reserves discovered through organic exploration in areas with high working interest. The agreements concerned the sale of: (i) a 10% interest to BP for a cash consideration of $375 million; and (ii) a 30% interest to Rosneft for a cash consideration of $1,125 million. Due to the fact that both transactions had retroactive economic effect to the beginning of 2016, Eni was also reimbursed of the share of capital and operating expenditures incurred at the divested interests to develop the field reserves for a total amount of approximately $1,500 million.

In March 2018, Eni signed an agreement with Mubadala Petroleum for the divestment of an additional 10% interest in Zohr for a cash consideration of $934 million. The transaction is subject to the fulfillment of certain conditions and all necessary authorizations from Egypt's authorities.

In December 2017, production start-up at Zohr was achieved by means of offshore wells and subsea facilities. The natural gas production is carried by sea-line to the first treatment train of onshore plant with a capacity of approximately 350 mmCF/d. The development plan includes the construction of additional seven treatment trains that will support production ramp-up to achieve a production plateau of approximately 2.7 BCF/d. Development activities progressed with drilling activities to start-up 20 planned production wells, of which 6 wells already drilled, and the construction of treatment facilities.

As of December 31, 2017, the aggregate development costs incurred by Eni for the Zohr project capitalized in the financial statements amounted to $3.0 billion (€2.5 billion at the EUR/USD exchange rate of December 31, 2017). The capital expenditures of the four-year plan for the production ramp-up at the Zohr field will be financed with net cash flow from operating activities at the Eni pricing assumptions for the Brent marker.

TABLE OF CONTENTS

As of December 31, 2017, Eni's proved reserves booked at the Zohr field amounted to 695 mmBOE.

The Baltim South West offshore project was sanctioned. The project provides to put into production six wells through the installation of a production platform and linkage facilities to the existing gas treatment plant in the Nooros area (Eni's interest 75%).

Other development activities concerned: (i) infilling activities and production optimization at the Gulf of Suez, North Port Said and Meleiha concessions; and (ii) start-up of three additional wells and the completion of the second and third treatment unit of the Nooros field to achieve a production of approximately 1 BCF/d.

In the medium term, management expects to increase Eni's production reflecting additions from the ramp-up of the Zohr fields and ongoing development projects.

Sub-Saharan Africa

Eni's operations in Sub-Saharan Africa are conducted mainly in Angola, Congo, Ghana, Mozambique and Nigeria. In 2017, Sub-Saharan Africa accounted for 19% of Eni's total worldwide production of oil and natural gas.

Angola. Eni has been present in Angola since 1980. In 2017, Eni's production averaged 135 KBOE/d. Eni's activities are concentrated in the conventional and deep offshore.

The main Eni's asset in Angola is the Block 15/ 06 (Eni operator with a 36.84% interest) with the West Hub project, where production started up in 2014 and the East Hub project with production start-up achieved in February 2017. Eni participates in other producing blocks: (i) Block 0 in Cabinda offshore (Eni's interest 9.8%); (ii) Development Areas in the Block 3 and 3/05-A (Eni's interest 12%) offshore the Congo Basin; (iii) Development Areas in the Block 14 (Eni's interest 20%) in the deep offshore west of Block 0; ±(iv) the Lianzi Development Area in the Block 14 K/A IMI (Eni's interest 10%), where a unitization was implemented with the Congo-Brazaville area; and (v) Development Areas in the Block 15 (Eni's interest 20%) in the deep offshore of the Congo Basin.

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

In November 2017, Eni signed with Sonangol an agreement to acquire a 48% interest and the operatorship of the onshore Cabinda North block, which was previously participated by Eni with a 15% interest. In addition, Eni and Sonangol signed a Memorandum of Understanding to define joint projects in the downstream sector, exploration

activities, development of associated and non-associated gas and renewable energy sector.
In February 2017, the East Hub project started-up production of Cabaça South East field through FPSO Armada Olombendo. In November 2017, Eni signed extension exploration rights of the Block 15/06 until 2020.
Development activities carried out in 2017 are: (i) the completion of project activities of the Ochigufu oil field, with production start-up achieved in March 2018, within the West Hub development project in the Block 15/06; (ii) the Vandumbu project in the Block 15/06 with the production start-up expected in 2019;

(iii) the drilling of development wells of the Mafumeira Sul project in the Block 0; and (iv) the development activities of the Kizomba Satellites phase 2 project and infilling activities in the Block 15.

Eni owns a 13.6% interest of Angola LNG, which runs the plant, located in Soyo, with a treatment capacity of approximately 350 BCF/y of feed gas and a liquefaction capacity of 5.2 mmtonnes/y of LNG. In 2017 production net to Eni averaged approximately 20 KBOE/d.

Congo. Eni has been present in Congo since 1968. In 2017, production averaged 75 KBOE/d net to Eni.

Eni's activities are concentrated in the conventional offshore in front of Pointe Noire and onshore Koilou region. Eni's main operated oil producing fields in Congo are the Zatchi (Eni's interest 55.25%), Loango (Eni's interest 42.5%), Ikalou (Eni's interest 100%), Djambala (Eni's interest 50%), Foukanda and Mwafi (Eni's interest 58%), Kitina (Eni's interest 52%), Awa Paloukou (Eni's interest 90%), M'Boundi (Eni's interest 83%), Kouakouala (Eni's interest 75%), Nené Marine and Litchendjili (Eni's interest 65%), Zingali and Loufika (Eni's interest 100%) fields.

Other non-operated producing areas, in which Eni owns a 35% interest are the Pointe Noire Grand Fond and Likouala permits.

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

Development activity carried out in 2017 was relate to the Nené Marine phase 2A project in the Marine XII block (Eni operator with a 65% interest), in detail: (i) installation and start-up of a new production platform; (ii) the construction of a sealine to export production to the Kitina hub; and (iii) start-up of seven additional production wells. Planned development activities include the drilling of additional production wells with start-up expected in 2018 and the construction of a sealine for the linkage to Litchendjili hub.

In the medium term, management expects to maintain production at the present level.

Ghana. Eni has been present in Ghana since 2009. In 2017, Eni's production averaged 8 KBOE/d.

Eni's main operated asset is the Offshore Cape Three Points (Eni's interest 44.44%) permits which is regulated by a concession agreement. The license expires in 2036.

In May 2017, the Offshore Cape Three Points development project production started up and the oil production ramped up to the planned peak production of 45 KBBL/d. The production is processed by a floating production, storage and offloading unit (FPSO), which will produce up to 85 KBOE/d through 18 underwater wells. By mid-2018 the non-associated gas will start up and sent to an Onshore Receiving Facilities located in Sanzule, to be sold to the local market.
Eni also operates the offshore exploration license Cape Three Points Block 4 (Eni's interest 42.47%).

TABLE OF CONTENTS

Mozambique. Eni has been present in Mozambique since 2006, following the award of the exploration license relating to Area 4 offshore the Rovuma Basin block, located in the north of the country.

In 2011, Eni made the important gas discovery of Mamba. The Mamba reservoir extends through Area 4 and the adjacent Area 1 operated by Anadarko. In 2012, Eni made the Coral gas discovery which falls entirely in Area 4. During the exploration period, which has expired in 2015, six Discovery Areas (DA) were identified. Pursuant to the Decree Law 02/2014 multiple plans of development can be submitted in respect of each DA. Under the Area 4 EPCC (Exploration and Production Concession Contract), each Plan of Development once approved by Government of Mozambique will give right to a Development and Production Period of the duration of 30 years, further extendable pursuant to the terms of the Area 4 EPCC and the applicable Petroleum Law.

Eni also operates the exploration offshore Block A-5A (Eni’s interest 70%), in the deep offshore of Zambesi.

In December 2017, Eni and ExxonMobil closed the sale of a 25% indirect interest in the Area 4 block, offshore Mozambique, through the sale of a 35.7% stake in Eni East Africa (EEA) that is the operator of Area 4. The agreed terms included a cash price of approximately $2.8 billion plus the contractual adjustments up to the closing date, including the reimbursement to Eni of share of capex incurred from the beginning of 2016 up to the completion date. Following completion of the transaction, Mozambique Rovuma Venture, former EEA, is now jointly owned by Eni and ExxonMobil each with a 35.7% stake and the remaining interest of 28.6% by CNPC.

Past transaction, Eni retains a 25% indirect interest in the Area 4 concession through a 35.7% stake in Mozambique Rovuma Venture, which is operator of the Area 4 concession with a 70% interest. The other partners in Area 4 are Galp, Kogas, ENH with a participating interest of 10% each and CNPC that holds a 20% indirect participation.

The other major event of 2017 was the final investment decision for the development of the gas reserves of the Coral discovery, exclusively located in Area 4.

The development activities of the Coral South project provides for the installation of a floating unit for the treatment, liquefaction and storage of natural gas (FLNG) with a capacity of approximately 3.4 mmtonnes/y fed by 6 subsea wells. Start-up is expected by mid-2022.

During 2017, project activities started and the following agreements were signed: (i) contracts for drilling, construction, installation and commissioning of production facilities; and (ii) project financing for the construction, installation and commissioning of the floating liquefaction unit (FLNG) to cover 60% of the investment. In December 2017, the financing agreement was closed and signed by 15 major international banks and guaranteed by 5 Export Credit Agencies. Further information is provided in “Item 19 – consolidated financial statement – footnote 38”.

Other development activities concerned the Mamba project according to its independent industrial plan, coordinated with the operator of Area 1 (Anadarko).

TABLE OF CONTENTS

Nigeria. Eni has been present in Nigeria since 1962. In 2017, Eni's oil&gas production averaged 104 KBOE/d located mainly onshore and offshore the Niger Delta.
In the development/ production phase Eni operates onshore Oil Mining Leases (OML) 60, 61, 62 and 63 (Eni's interest 20%), offshore OML 125 (Eni's interest 100%) and OPL 245 (Eni's interest 50%), holding interests in OML 118 (Eni's interest 12.5%) and in OML 119 and 116 Service Contracts. As partners of SPDC JV, the largest joint venture in the country, Eni also holds a 5% interest in 17 onshore blocks and in 1 conventional offshore block and with a 12.86% in 2 conventional offshore blocks.
In the exploration phase Eni operates offshore OML 134 (Eni's interest 85%), OPL 2009 (Eni's interest 49%), and onshore OPL 282 (Eni's interest 90%) and OPL 135 (Eni's interest 48%). Eni also holds a 12.5% interest in non-operated OML 135.
Exploration and production activities in Nigeria are regulated mainly by Production Sharing Agreements and concession contracts as well as service contracts, in two blocks, where Eni acts as contractor for the State-owned Company.
Development activities carried out in 2017 are: (i) rigless programs to support production as well as maintenance and rehabilitation of the facilities damaged due to bunkering and sabotage in the OMLs 60, 61, 62 and 63 blocks; (ii) the completion of the Forcados-Yokri project in the OML 43 block (Eni's interest 5%) and the Gbaran 2A/2b and Associated gas project in the OML 28 block (Eni's interest 5%) to supply natural gas to the Bonny liquefaction plant. In particular, in the year, the tie-in of production wells and the upgrading of existing treatment plants were completed.
Eni holds a 10.4% interest in the Nigeria LNG Ltd joint venture, which runs the Bonny liquefaction plant located in the Eastern Niger Delta. The plant has treatment capacity of approximately 1,236 BCF/y of feed gas and a production capacity of 22 mmtonnes/y of LNG by six trains. Natural gas supplies to the plant are currently provided under a gas supply agreements from the SPDC JV, TEPNG JV and the NAOC JV. In 2017, the Bonny liquefaction plant processed approximately 1,130 BCF. LNG production is sold under long-term contracts and exported to the United States, Asian and European markets by the Bonny Gas Transport fleet, wholly owned by Nigeria LNG.
The acquisition of the OPL 245 property made by Eni in 2011 is the subject of certain judicial proceedings describe in "Item 19 – consolidated financial statement – footnote 38".
In January 2017, Eni signed with the Minister of State for Petroleum Resources and Chairman of the Board of the Nigerian National Petroleum Corporation (NNPC) a Memorandum of Understanding, which strengthens cooperation in the energy sector.

TABLE OF CONTENTS

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 2017, Eni's operations in Kazakhstan accounted for 7% of its total worldwide production of oil and natural gas.

In 2017, Eni and KazMunayGas (KMG) signed an agreement, closed in December 2017, for the transfer to Eni of the 50% stake for exploration and production activities in the Isatay block located in the Kazakh sector of the Caspian Sea. The Isatay block will be operated by a joint operating company established by KMG and Eni on a 50/50 basis.

Eni, KMG and the other partners signed with the Ministry of Energy of the Republic of Kazakhstan, and the Kazakh Committee of geology and subsoil use, a Memorandum of Understanding to evaluate future cooperation terms in the Kazakh-Russian Pre-Caspian Basin recording certain significant oil discoveries

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

In addition to Eni, the partners of the Consortium are the Kazakh national oil company, KazMunayGas, with a participating interest of 16.88%, the international oil companies Total, Shell and ExxonMobil, each with a participating interest of 16.81%, CNPC with 8.33%, and Inpex with 7.56%.

Ramp-up and stabilization of the production level at the Kashagan field progressed in 2017. Although gas re-injection started later than initially planned, it has been stepped-up in the course of the year and will allow to achieve the target production capacity of 370 KBBL/d when fully operational.

Further activities are in progress to increase production capacity up to 450 KBBL/d by installing additional gas compression capacity through the conversion of production wells into injection wells and the upgrading of the existing facilities. Studies are underway to evaluate a possible optimization of the CC01 gas re-injection project. The concept design envisions the installation of a new compressor unit intended to furnish an additional gas re-injection capacity to support production ramp-up.

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

As of December 31, 2017, Eni’s proved reserves booked for the Kashagan field amounted to 620 mmBOE, slightly increased from 608 mmBOE in 2016.

TABLE OF CONTENTS

As of December 31, 2017, the aggregate costs incurred by Eni for the Kashagan project capitalized in the financial statements amounted to $9.8 billion (€8.2 billion at the EUR/USD exchange rate of December 31, 2017). This capitalized amount included: (i) $7.3 billion relating to expenditure incurred by Eni for the development of the oil field; and (ii) $2.5 billion relating primarily to accrued finance charges and expenditures for the acquisition of interests in the Consortium from exiting partners upon exercise of pre-emption rights in previous years.

Karachaganak. Located onshore in West Kazakhstan, Karachaganak is a liquid and gas field. Operations are conducted by the Karachaganak Petroleum Operating consortium (KPO) and are regulated by a PSA lasting 40 years, until 2037. Eni and Shell are co-operators of the venture. Eni’s interest in the Karachaganak project is 29.25%.

In 2017, production of the Karachaganak field averaged 247 KBBL/d of liquids (54 KBBL/d net to Eni) and 859 mmCF/d of natural gas (188 mmCF/d net to Eni). This field is developed by producing liquids from the deeper layers of the reservoir. The gas is marketed (about 51%) at the Russian gas plant in Orenburg and the remaining volumes is utilized for re-injecting in the higher layers and the production of fuel gas. Approximately 91% of liquid production are stabilized at the Karachaganak Processing Complex (KPC) with a capacity of approximately 250 KBBL/d and exported to Western markets through the Caspian Pipeline Consortium (Eni’s interest 2%) and the Atyrau-Samara pipeline. The remaining volumes of non-stabilized liquid production (approximately 16 KBBL/d) are marketed at the Russian terminal in Orenburg.

Within the gas treatment expansion projects of the Karachaganak field, the detailed engineering design of the Karachaganak Debottlenecking project is expected to be completed shortly and a Final Investment Decision (FID) is expected to be made in the second quarter of 2018. Additional re-injection capacity will be ensured by installing a new re-injection facility in addition to the existing ones.

As of December 31, 2017, Eni’s proved reserves booked for the Karachaganak field amounted to 530 mmBOE, reporting a decrease of 83 mmBOE from 2016 due to an increased marker Brent price used in the reserves estimation process.

Rest of Asia

In 2017, Eni’s operations in the Rest of Asia accounted for 6% of its total worldwide production of oil and natural gas.

China. Eni has been present in China since 1984 with activities located in the South China Sea. In 2017, Eni’s production amounted to 2 KBOE/d.

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

In 2017, hydrocarbons were produced from the offshore Blocks 16/19 through 3 platforms connected to an FPSO.

Indonesia. Eni has been present in Indonesia since 2001. In 2017, Eni’s production mainly composed of gas, amounted to 35 KBOE/d. Activities are concentrated in the Eastern offshore and onshore of East Kalimantan, offshore Sumatra, and offshore and onshore of West Timor and West Papua; in total, Eni holds interests in 14 blocks.

Exploration and production activities in Indonesia are regulated by PSAs.

Production started up in the Jangkrik gas project in the Muara Bakau block (Eni operator with a 55% interest) by means of ten offshore wells linked to the Floating Production Unit (FPU) with a production of approximately 650 mmCF/d (equal to 120 KBOE/d). Natural gas production is processed by the FPU and then delivered by pipeline to the onshore plant, which is linked to the East Kalimantan transport system to feed Bontang liquefaction plant. The LNG is sold under long-term contracts, partly to PT Pertamina and partly to Eni, which will sell up to 11 million tonnes for 15 years as part of the supply agreement signed with the Pakistan LNG state company.

TABLE OF CONTENTS

Exploration activities yielded positive results with the Merakes 2 appraisal well confirming the mineral potential of the Merakes gas discovery in the western area of the East Sepinggan block (Eni operator with an 85% interest). The discovery is located nearby the operated Jangkrik project.

Iraq. Eni has been present in Iraq since 2009. Eni is leading a consortium of partners including international companies and the national oil company Missan Oil, with a 41.6% working interests in charge of executing a rehabilitation and a development plan at the Zubair oil field.

Development and production activities at the Zubair field are regulated by a technical service contract. This contractual scheme establishes an oil entitlement mechanism and an associated risk profile similar to those applicable to Production Sharing contracts.

In 2017, production of the Zubair field averaged 40 KBBL/d net to Eni.

The first stage of development activities (Rehabilitation Plan) of the Zubair field has been completed.

The consortium commitment includes the execution of an additional development phase (Enhanced Redevelopment Plan) of the Zubair field, to achieve a production plateau of 700 KBBL/d. This phase also contemplates utilization of the associated gas to power generation. The large part of production capacity and relevant facilities to treat the targeted production plateau have been already installed; the field reserves will be progressively put into production by drilling additional productive wells over the next few years.

Myanmar. Eni has been present in Myanmar since 2014. Eni is operator of four Production Sharing Contracts; two onshore blocks RSF-5 and PSC-K (Eni’s interest 90% in both leases) and two offshore blocks MD-02 and MD-04 (Eni’s interest 40% in both leases). The contracts foresee, for the onshore blocks, an exploration period of six years subdivided into three phases and for the offshore blocks a study period of two years, followed by an exploration period of six years, subdivided in 3 phases.

Oman. In 2017, Eni signed with the Government of the Sultanate and the state oil company OOCEP an Exploration and Production Sharing Agreement for the Block 52, located offshore Oman. In addition, at the same time, Eni signed an agreement to assign interest in the block to the Qatar Petroleum oil company. The agreement is subject to approval by the relevant Authorities of the country. Following approval of these agreements, Eni will retain the operatorship of the block with a 55% interest.

In May 2017, Eni signed with the Oman Oil Company (OOC) state company a Memorandum of Understanding for cooperation in oil&gas sector.

Pakistan. Eni has been present in Pakistan since 2000. In 2017, Eni’s production mainly composed of gas amounted to 22 KBOE/d.

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

Eni’s main permits in the country relate to the fields of Bhit/Bhadra (Eni operator with a 40% interest), Sawan (Eni’s interest 23.68%) and Zamzama (Eni’s interest 17.75%), which in 2017 accounted for approximately 80% of Eni’s production in Pakistan.

Production optimization through drilling activities of new development wells represents the main activity currently performed in the above listed fields to mitigate the natural field production decline.

Russia. Eni is present in Russia through three joint ventures with Rosneft for the exploration and development of the Fedynsky and the Central Barents licenses (Eni’s interest 33.33%) located in the Russian Barents Sea and Western Chernomorsky license (Eni’s interest 33.33%) in the Black Sea since 2013.

The Russia upstream sector is the target of certain international sanctions that are described in “Item 3 – Risk factors”.

Turkmenistan. Eni started its activities in Turkmenistan with the purchase of the British company Burren Energy plc in 2008. Activities are focused on the onshore Nebit Dag Area in the Western part of the country. The license expires in 2032.

TABLE OF CONTENTS

In 2017, Eni's production averaged 8 KBOE/d.

Exploration and production activities in Turkmenistan are regulated by PSAs.

Production derives mainly from the Burun oil field. Oil production is shipped to the Turkmenbashi refinery plant. Eni receives, by means of a swap arrangement with the Turkmen Authorities, an equivalent amount of oil at the Okarem terminal, close to the South coast of the Caspian Sea. Eni's entitlement is sold FOB. Associated natural gas is used for gas lift system. The remaining amount is delivered to the national oil company Turkmenneft, via national grid.

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

United Arab Emirates. In March 2018, Eni signed with the Supreme Petroleum Council (SPC) and the Abu Dhabi National Oil Company (ADNOC) two Concession Agreements related to the acquisition of a 5% participating interest in the Lower Zakum oil field and a 10% participating interest in the Umm Shaif and Nasr oil, condensates and natural gas fields, in the offshore of Abu Dhabi, for a consideration of $875 million with duration of 40 years.

Vietnam. Eni has been present in Vietnam since 2012 and is operator of five offshore Production Sharing Contracts, two of which are held with 100% interest (Block 116 and Block 122) and three are in Joint Venture (Block 114 Eni's interest 50%, Block 120 – Eni's interest 66.67%, Block 124 – Eni's interest 60%).

Americas

In 2017, Eni's operations in the Americas area accounted for 9% of its total worldwide production of oil and natural gas.

Ecuador. Eni has been present in Ecuador since 1988. Operations are performed in Block 10 (Eni's interest 100%) located in the Oriente Basin, in the Amazon forest. In 2017, Eni's production averaged 12 KBBL/d.

Exploration and production activities in Ecuador are regulated by a service contract that expires in 2033.

Block 10 production is processed by a Central Production Facility and transported to the Pacific Coast through a pipeline network.

In 2017, development activities of the Villano Phase VI project were completed with the drilling and production start-up of three infilling wells.

TABLE OF CONTENTS

Mexico. Eni has been present in Mexico since 2015. Eni is operator of the offshore Block 1 (Eni’s interest 100%) and is planning to develop the Amoca, Miztón and Tecoalli discoveries, located in the shallow waters of the Gulf of Mexico, regulated by PSA.
In June 2017, Eni was awarded the operatorship of Block 10 (Eni’s interest 100%), Block 14 (Eni’s interest 60%) and Block 7 (Eni’s interest 45%) located in the Sureste basin. Furthermore, in February 2018, Eni was awarded a 65% interest and the operatorship of Block 24. The new blocks are close to Area 1 block.
In March 2018, Eni was awarded the operatorship of the Block 28 (Eni’s interest 75%), located in Cuenca Salina basin, in offshore Mexico. The contract award is subject to approval from the authorities.
Exploration activities yielded positive results in the Area 1 block with: (i) the Amoca-2 and Amoca-3 appraisal oil wells; (ii) the first delineation well of the Miztón oil discovery; and (iii) the Teocalli2 appraisal oil well. Eni submitted an integrated development plan of all the three discoveries to the relevant Authorities. Production start-up is expected in 2019.
Trinidad and Tobago. Eni has been present in Trinidad and Tobago since 1970. In 2017, Eni’s production averaged 55 mmCF/d. Eni owns a 17.3% interest in the North Coast Marine Area 1 Block, located offshore North of Trinidad. Exploration and production activities in Trinidad and Tobago are regulated by a PSA.
Production is provided by the Chaconia, Ixora, Hibiscus, Ponsettia, Bougainvillea and Heliconia gas fields. Production is supported by two fixed platforms linked to the Hibiscus processing facility. Natural gas is used to feed trains 2, 3 and 4 of the Atlantic LNG liquefaction plant on Trinidad’s coast and it is sold under long-term contracts with prices linked to the United States, as well as alternative destinations markets.

United States. Eni has been present in the United States since 1968. Activities are performed in the shallow and deep offshore of the Gulf of Mexico, onshore and offshore in Alaska, and in Texas onshore.
In 2017, Eni's oil&gas production was 74 KBOE/d mainly from the Gulf of Mexico and Alaska fields.
Exploration and production activities in the United States are regulated by concessions.
Eni holds interests in 75 exploration and production blocks in the Gulf of Mexico, of which 35 are operated by Eni. The main operated fields are Allegheny and Appaloosa (Eni's interest 100%), Pegasus (Eni's interest 85%), Longhorn, Devils Towers and Triton (Eni's interest 75%). Eni also holds interests in Europa (Eni's interest 32%), Hadrian South (Eni's interest 30%), Medusa (Eni's interest 25%), Lucius (Eni's interest 8.5%), K2 (Eni's interst 13.4%), Frontrunner (Eni's interest 37.5%) and Heidelberg (Eni's interest 12.5%) fields.

TABLE OF CONTENTS

In 2017, the FID of the Lucius Subsequent Development project (Eni's interest 8.5%) was sanctioned. The development activities provide for the drilling and completion of three subsea production wells and linkage to the existing facilities in the area. Start-up is expected in 2019 with a production plateau of 2 KBOE/d net to Eni.

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

Eni holds interests in 42 exploration and development blocks in Alaska, with interests ranging from 30 to 100%; Eni is the operator in 26 of these blocks.

Eni's production is provided by Nikaitchuq (Eni operator with a 100% interest) and Oooguruk (Eni's interest 30%) fields with a 2017 overall net production of approximately 20 KBBL/d.

In Texas onshore, Eni's production comes from the Alliance Area (Eni's interest 27.5%).

Venezuela. Eni has been present in Venezuela since 1998. In 2017, Eni's production averaged 61 KBOE/d.

Activity is concentrated both offshore (Gulf of Venezuela and Gulf of Paria) and onshore in the Orinoco Oil Belt.

Eni's production comes from the Perla gas field (Eni's interest 50%), in the Gulf of Venezuela, the Corocoro field (Eni's interest 26%), in the Gulfo de Paria, and the Junin 5 oil field (Eni's interest 40%), located in the Orinoco Oil Belt.

Eni is also participating with a 19.5% interest in Petrolera Güiria for oil exploration and with a 40% interest in Punta Pescador and Gulfo de Paria Ovest for gas exploration, both located offshore in the eastern Venezuela.

Australia and Oceania

Eni's operations in Australia and Oceania area are conducted mainly in Australia. In 2017, the area of Australia and Oceania accounted for 1% of Eni's total worldwide production of oil and natural gas.

Australia. Eni has been present in Australia since 2001. In 2017, Eni's production of oil and natural gas averaged 21 KBOE/d. Activities are focused on conventional and deep offshore fields.

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

The main production blocks in which Eni holds interests are WA-33-L (Eni's interest 100%) and JPDA 03-13 (Eni's interest 10.99%). In the appraisal and development phase Eni holds interests in NT/RL8 (Eni's interest 100%) and NT/RL7 (Eni's interest 65%). In addition Eni holds interest in 6 exploration licenses, of which 1 in the JPDA.

In 2017, Eni acquired a 32.5% interest of the Evans Shoal gas field in the NT/RL7 offshore license in the northern Australia, nearby the Darwin liquefaction gas plant. The agreement received all necessary approvals. Following this acquisition Eni retains the operatorship with a 65% interest.

Capital expenditures

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

TABLE OF CONTENTS

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

The Iran Threat Reduction and Syria Human Rights Act of 2012 (ITRA) created a new subsection (r) in Section 13 of the Exchange Act which requires a reporting issuer to provide disclosure if the issuer or any of its affiliates engaged in certain enumerated activities relating to Iran, including activities involving the Government of Iran. In accordance with our general business principles and Code of Ethics, Eni seeks to comply with all applicable international trade laws including applicable sanctions and embargoes. The activities referred to below have been conducted outside the U.S. by non-U.S. Eni subsidiaries. For purposes of the disclosure below, amounts have been converted into U.S. dollars at the average or spot exchange rate, as appropriate.

In 2017, Eni fully recovered the overdue trade receivable owed by Iranian state-owned companies relating to the cost recovery of past projects due to enactment of the agreements signed in 2016. Further information is provided in "Item 19-consolidated financial statements under footnote 11". Eni had no payables towards NIOC as of December 31, 2017. Eni made payments in the region of $0.8 million to the Iranian Social Security Organization in connection to health and social security insurance for which Eni retains at the balance sheet date a residual payable amounting to approximately $8 million date, which will be settled upon termination of our presence in the country.

Finally, in 2017 our Refining & Marketing business sold a limited amount of refined products (16,735 liters for a consideration of approximately €17,000), mainly jet fuels, to an Italian third-party service provider, which in turn re-fuelled an aircraft of the Iranian company Meraj Air.

Gas & Power

Eni's Gas & Power segment engages in supply, trading and marketing of gas and electricity, international transport, and LNG supply/marketing and trading. This segment also includes electricity generation activities. In 2017, Eni's worldwide sales of natural gas amounted to 80.83 BCM. Sales in Italy amounted to 37.43 BCM, while sales in European markets were 38.23 BCM that included 3.89 BCM of gas sold to certain importers to Italy.

The business results of operations in 2017 and its strategy are described in Item 5 – 2015-2017 Group results of operations and Item 5 – Management's expectations of operations.

Supply of natural gas

In 2017, Eni's total supply of natural gas was 78.28 BCM of natural gas, down by 4.36 BCM, or 5.3% from 2016. Gas volumes supplied outside Italy (73.23 BCM from consolidated companies), imported in Italy or sold outside Italy, represented approximately 94% of total supplies, down by 3.41 BCM, or 4.4% compared to the previous year, due to lower volumes purchased in the Netherlands (down by 4.40 BCM) following a contract termination, in Qatar (down by 0.92 BCM) and in Norway (down by 0.70 BCM) partially offset by higher purchases in the United Kingdom (up by 0.28 BCM) and in Algeria (up by 0.28 BCM).

Supplies in Italy (5.05 BCM) decreased by 15.8% from 2016 due to lower equity production.

In 2017, main gas volumes from equity production derived from: (i) Italian gas fields (4.1 BCM); (ii) certain Eni fields located in the British and Norwegian sections of the North Sea (1 BCM); Libyan fields (1.5 BCM); (iv) Indonesia (0.4 BCM); (v) other European areas, mainly in Croatia (2.6 BCM).

Considering also direct sales of the Exploration & Production segment and LNG supplied from the Bonny liquefaction plant in Nigeria, supplied gas volumes from equity production were approximately 13.84 BCM representing 15% of total volumes available for sale.

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

Natural gas supply	2017	2016	2015
	(BCM)		
Italy	5.05	6.00	6.73
Outside Italy	73.23	76.64	78.66
Russia	28.09	27.99	30.33
Algeria (including LNG)	13.18	12.90	6.05
Libya	4.76	4.87	7.25
the Netherlands	5.20	9.60	11.73
Norway	7.48	8.18	8.40
the United Kingdom	2.36	2.08	2.35
Hungary	0.04	0.02	0.21
Qatar (LNG)	2.36	3.28	3.11
Other supplies of natural gas	6.71	5.81	7.21
Other supplies of LNG	3.05	1.91	2.02
Total supplies of subsidiaries	78.28	82.64	85.39
Withdrawals from (input to) storage	0.31	1.40	
Network losses, measurement differences and other changes	(0.45)	(0.21)	(0.34)
Volumes available for sale of Eni's subsidiaries	78.14	83.83	85.05
Volumes available for sale of Eni's affiliates	2.69	2.48	2.67
Total volumes available for sale	80.83	86.31	87.72

Sales of natural gas

In 2017, natural gas sales amounted to 80.83 BCM (including Eni's own consumption, Eni's share of sales made by equity-accounted entities), representing a decrease of 5.48 BCM, or 6.3% from the previous year. Sales in Italy (37.43 BCM) decreased by 2.6% from 2016. Lower sales to spot market, volumes sold to small and medium-sized enterprises segment and to services sector were offset by the higher sales to thermoelectrical segment. Sales in the European markets amounted to 34.34 BCM, a decrease of 9.8% or 3.72 BCM from 2016.

Sales to long-term buyers were down by 11% compared to the previous year due to the shorter availability of Libyan output. Sales in the Extra European markets (5.17 BCM) decreased by 0.28 BCM or 5.1% due to lower LNG sales in Japan, Argentina, United Arab Emirates, partly offset by higher volumes sold in South Korea and China.

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

Natural gas sales by entities	2017	2016	2015
	(BCM)		
Total sales of subsidiaries	77.52	83.34	84.94
Italy (including own consumption)	37.43	38.43	38.44
Rest of Europe	36.10	40.52	41.14
Outside Europe	3.99	4.39	5.36
Total sales of Eni's affiliates (Eni's share)	3.31	2.97	2.78
Italy			

Rest of Europe	2.13	1.91	1.75
Outside Europe	1.18	1.06	1.03
Worldwide gas sales	80.83	86.31	87.72

TABLE OF CONTENTS

Natural gas sales by market	2017	2016	2015
	(BCM)		
ITALY	37.43	38.43	38.44
Wholesalers	8.36	7.93	4.19
Italian gas exchange and spot markets	10.81	12.98	16.35
Industries	4.42	4.54	4.66
Medium-sized enterprises and services	0.93	1.72	1.58
Power generation	2.22	0.77	0.88
Residential	4.51	4.39	4.90
Own consumption	6.18	6.10	5.88
INTERNATIONAL SALES	43.40	47.88	49.28
Rest of Europe	38.23	42.43	42.89
Importers in Italy	3.89	4.37	4.61
European markets	34.34	38.06	38.28
Iberian Peninsula	5.06	5.28	5.40
Germany/Austria	6.95	7.81	5.82
Benelux	5.06	7.03	7.94
Hungary		0.93	1.58
United Kingdom/Northern Europe	2.21	2.01	1.96
Turkey	8.03	6.55	7.76
France	6.38	7.42	7.11
Other	0.65	1.03	0.71
Extra European markets	5.17	5.45	6.39
WORLDWIDE GAS SALES	80.83	86.31	87.72

The LNG business

Eni LNG business can count currently on a portfolio of contracted long-term supplies mainly from Qatar, Nigeria, Oman and Algeria. Starting from 2017, the G&P LNG business marketed volumes of gas produced at the E&P large Jangkrik gas complex, off Indonesia. In the plan period, Eni intends to develop its LNG business by leveraging on the integration with the E&P segment and the valorization of the equity gas. Final markets of that gas include the Chinese market and other areas. The business's profitability will be also driven by enhancing the commercial presence in premium markets and continuing integration with trading activities.

LNG sales	2017	2016	2015
	(BCM)		
G&P sales	8.3	8.1	9.0
Rest of Europe	5.2	5.2	4.8
Extra European markets	3.1	2.9	4.2
E&P sales	5.9	4.3	4.5
Liquefaction plants:			
- Soyo (Angola)	0.7	0.1	

- Bontang (Indonesia)	1.3	0.4	0.5
- Point Fortin (Trinidad & Tobago)	0.6	0.7	0.7
- Bonny (Nigeria)	2.9	2.6	2.8
- Darwin (Australia)	0.4	0.5	0.5
	14.2	12.4	13.5

TABLE OF CONTENTS

Electricity sales and power generation

Electricity sales

As part of its marketing activities in Italy, Eni engages in selling electricity on the Italian market principally on the open market, on the Italian Stock Exchange for electricity and at industrial sites. Supplies of electricity include both own production volumes through gas-fired, combined-cycle facilities and purchases on the open market. This activity has been developed in order to capture further value along the gas value chain by leveraging on the Company's large gas availability. In addition, with the aim of developing and retaining valuable customers in the residential segment and middle to large industrial users, the Company has been developing a commercial offer that provides the combined supply of gas, power and fuels.

In 2017, power sales (35.33 TWh) were directed to the free market (75%), the Italian Power Exchange (15%), industrial sites (8%) and others (2%). Compared to 2016, electricity sales were down by 0.96 TWh or by 3.5%, due to lower volumes sold to middle market, wholesalers, residential segment and small and medium-sized enterprises, partially offset by higher volumes sold to large customers.

Power availability	2017	2016	2015
	(TWh)		
Power generation sold	22.42	21.78	20.69
Trading of electricity(a)	12.91	15.27	14.19
	35.33	37.05	34.88
Power sales by market			
Free market(a)	26.53	27.49	25.90
Italian Exchange for electricity	5.21	5.64	5.09
Industrial plants	3.01	3.11	3.23
Other(a)	0.58	0.81	0.66
	35.33	37.05	34.88

(a)
Include positive and negative imbalances (differences between power introduced in the grid and the one planned).

Power generation

Eni's power generation sites are located in Ferrera Erbognone, Ravenna, Mantova, Brindisi, Ferrara and Bolgiano. In 2017, power generation was 22.42 TWh, up by 0.64 TWh or by 2.9% from 2016 mainly due to higher production at Ferrera Erbognone, Ravenna, Brindisi, following increasing demand. As of December 31, 2017, installed operational capacity was 4.7 GW, unchanged compared to December 31, 2016. Electricity trading (12.91 TWh) reported a decrease of 15.5% thanks to the optimization of inflows and outflows of power.

Site	Total installed capacity in 2017 (GW)	Technology	Fuel
Brindisi	1.3	CCGT	gas
Ferrera Erbognone	1.0	CCGT	gas/syngas
Mantova	0.8	CCGT	gas
Ravenna	1.0	CCGT	gas

Ferrara(a)	0.4	CCGT	gas
Bolgiano	0.1	Power station	gas
	4.7		

(a)
Eni's share of capacity.

TABLE OF CONTENTS

Power generation		2017	2016	2015
Purchases				
Natural gas	(mmCM)	4,359	4,334	4,270
Other fuels	(ktoe)	392	360	313
- of which steam cracking		104	105	87
Production				
Electricity	(TWh)	22.42	21.78	20.69
Steam	(ktonnes)	7,551	7,974	9,318
Installed generation capacity	(GW)	4.7	4.7	4.9

International transport

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

Likewise, Eni has contracted long-term access and transport capacity at the main entry points of the Italian national grid. Management believes that from 2019 the Company’s ship-or-pay obligations towards the Italian TSO might be softened at the entry points of the Italian gas transport network via a regulatory change. As a matter of fact, from thermal year October 2017 – October 2018 Eni is already allowed to defer utilization of entry capacities booked with a multi-year term over a period of three years thus reducing the incidence on the profit and loss of the sunk costs of the transport capacity.

Eni also retains ownership interests in certain pipeline companies which run and operate the facility by selling transportation capacity under long-term ship-or-pay contracts to both shareholders and third-party shippers. The main assets of Eni’s transport activities are provided in the table below.

International Transport infrastructure Route

	Lines	Total length	Diameter	Transport capacity(1)	Transit capacity(2)	Compression stations
	(units)	(km)	(inch)	(BCM/y)	(BCM/y)	(No.)
TTPC (Oued Saf Saf-Cap Bon)	2 lines of km 370	740	48	34.3	33.2	5
TMPC (Cap Bon-Mazara del Vallo)	5 lines of 155	775	20/26	33.5	33.5	
GreenStream (Mellitah-Gela)	1 line of km 520	520	32	8.0	8.0	1
Blue Stream (Beregovaya-Samsun)	2 lines of km 387	774	24	16.0	16.0	1

(1)
Includes both transit capacity and volumes of natural gas destined to local markets and withdrawn at various points along the pipeline.

(2)
The maximum volume of natural gas which is input at various entry points along the pipeline and transported to the next pipeline.

International transport activities

The TTPC pipeline, 740-kilometer long, is made up of two lines that are each 370-kilometers long with a transport capacity of 34.3 BCM/y and five compression stations. This pipeline transports natural gas from Algeria across Tunisia from Oued Saf Saf at the Algerian border to Cap Bon on the Mediterranean coast where it links with the TMPC pipeline.

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

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

TABLE OF CONTENTS

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

Capital expenditures

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

Refining & Marketing & Chemicals

Refining & Marketing

Eni's Refining & Marketing business engages in the supply and refining of crude oil, as well as in the marketing of refined products primarily in Europe. In Italy, Eni is the largest refining and marketing operator in terms of capacity and market share. Company operations are fully integrated through refining, supply, logistics and marketing in order to maximize cost efficiencies and operational effectiveness.

In 2017 refining margins in the Mediterranean area increased by approximately 19% y-o-y due to better prices of refined products relative to the cost of the petroleum feedstock.

Management believes that refining margins in the short-term will remain stable at the 2017 level. In the medium-term, spreads between products and crude may widen as a consequence of the IMO 2020 regulations, which will lead, among other solutions, to the substitution of bunker fuel oil with cleaner fuels (gasoil, ULSFO and LNG) that could be short in the first period of law application, with benefit for high conversion refineries. In the longer term, refinery margins will normalize, as a result of supply-demand re-alignment thanks investments by both refining companies (fuel oil destruction units) as well as ship-owners (scrubbers, retrofitting, new ships/engines).

The business results of operations in 2017 and its strategy are described in Item 5 – 2015-2017 Group results of operations and Item 5 – Management's expectations of operations.

Supply

In 2017, a total of 24.28 mmtonnes of crude were purchased (compared with 23.35 mmtonnes in 2016), of which 3.51 mmtonnes by equity crude oil. The breakdown by geographic area was the following: approximately 40% of purchased crude came from the Middle East, 19% from Central Asia, 15% from Russia, 12% from Italy, 10% from North Africa, 2% from North Sea, 1% from West Africa, and 1% from other areas.

Refining

In 2017, Eni refinery capacity (balanced with conversion capacity) was approximately 27.4 mmtonnes (equal to 548 KBBL/d), with a conversion index of 54%. Conversion index is a measure of refinery complexity. The higher the index, the wider the range of crude qualities and feedstock that a refinery is able to process thus enabling refineries to benefit from the cost economies arising from the discount – versus the benchmark – at which certain qualities of crude (particularly the heavy ones) may be supplied. Eni's 100% owned refineries have a balanced capacity of 19.4 mmtonnes (equal to 388 KBBL/d), with a 55% conversion index. In 2017, Eni's refineries throughputs in Italy and outside Italy were 24.02 mmtonnes. The refinery utilization rate, ratio between throughputs and refinery capacity, is 82.6%.

TABLE OF CONTENTS

Refining system in 2017

	Ownership (%)	Balanced refining capacity (Eni's share) (KBBL/d)	Utilization rate (Eni's share) %	Conversion index(1) (%)	Fluid catalytic cracking (FCC)(2) (KBBL/d)	Residue conversion(2) (KBBL/d)	Hydro-cracking(2) (KBBL/d)	Visbreaking/ Thermal Cracking(2) (KBBL/d)
Wholly-owned refineries		388	83	55	34	40	71	29
Italy								
Sannazzaro	100	200	83	73	34	14	51	29
Taranto	100	104	68	56		26	20	
Livorno	100	84	99	11				
Partially owned refineries		160	104	52	143	25	75	27
Italy								
Milazzo	50	100	109	60	45	25	32	
Germany								
Vohburg/Neustadt (Bayernoil)	20	41	93	36	49			
Schwedt	8.33	19	102	42	49		43	27
Total		548	89	54	177	65	146	56

(1)
Conversion index: catalytic cracking equivalent capacity/topping capacity (%wt).

(2)
Conversion unit capacities are 100%.

Italy

Eni's refining system in Italy is composed of the wholly-owned refineries of Sannazzaro, Livorno and Taranto, as well as its 50% stake in the Milazzo refinery in Sicily. Eni's refineries operate to maximize asset value according to market conditions and the integration with marketing activities.

The Sannazzaro refinery has a balanced capacity of 200 KBBL/d and a conversion index of 73%. Located in the Po Valley, in the center of the Northern Italy, Sannazzaro is one of the most efficient refineries in Europe. The high flexibility and conversion capacity of this refinery allows it to process a wide range of feedstock. The main equipments in the refinery are: two primary distillation columns and two associated vacuum units, three desulphurization units, a fluid catalytic cracker (FCC), two hydrocrackers (HdC), two reforming units, a visbreaking thermal conversion unit integrated with a gasification producing a syngas used in a combined cycle power generation, and finally the Eni Slurry Technology (EST) plant, started up at the end of 2013. The EST plant exploits a proprietary technology to convert extra heavy crude residues (vacuum and visbreaking tar) into naphtha and middle distillates, with a conversion factor of 95%.

In January 2018 Eni has sold the licence and basic engineering project to the Chinese company Sinopec the largest refining company in the world, for the use of the EST conversion proprietary technology.

The Taranto refinery has a balanced capacity of 104 KBBL/d and a conversion index of 56%. Taranto has a strong market position due to the fact that is the only refinery in Southern Continental Italy, and is upstream integrated with the Val d'Agri fields in Basilicata (Eni 60.77%) through a pipeline. The main equipments are a topping-vacuum unit, a hydrocracking, a platforming unit and two desulphurization units.

The Livorno refinery, with a balanced refining capacity of 84 KBBL/d and a conversion index of 11%, is dedicated to the production of lubricants and specialties. The refinery is connected by pipeline to a depot in Florence (Calenzano). The refinery has a topping-vacuum unit, a platforming unit, two desulphurization units and a de-aromatization unit (DEA) – for the production of fuels; a propane de-asphalting (PDA), aromatics extraction and de-waxing units, for the production of base oils; a blending and filling plant – for the production of finished lubricants.

The Milazzo refinery (Eni 50%) has a balanced capacity of 200 KBBL/d and a conversion index of 60%. Located in Sicily, Milazzo is mainly dedicated to export and to the supply of Italian coastal depots. The main equipments in the refinery are: two primary distillation columns and a vacuum unit, two desulphurization units, a fluid catalytic cracker (FCC), one hydrocracker (HdC), one reforming unit and one LC fining (ebullated bed residue conversion).

TABLE OF CONTENTS

Outside Italy

In Germany, Eni owns an interest of 8.33% stake in the Schwedt refinery (PCK) and an interest of 20% in the Vohburg and Neustadt refineries (Bayernoil). Eni's refining capacity in Germany is 60 KBBL/d to supply Eni's distribution network in the country.

Green refineries

	Ownership share (%)	Capacity (2017) (ktonnes/y)	Capacity (at regime) (ktonnes/y)	Throughput (2017) (ktonnes/y)
Wholly-owned				
Venezia	100	360	560	242
Gela	100		750	
Total green refineries		360	1,310	242

Green Refining

Eni fully owns the green refinery of Venice and the site of Gela, where another green refinery is under construction. The Venice green refinery started production in June 2014, with a production capacity of 360 ktonnes/ y. The refinery leverages on the proprietary EcofiningTM technology to transform vegetable oil in hydrogenated bio-fuels. A second phase of development is underway. At full capacity, the refinery production will satisfy approximately half of Eni bio-fuels needs required for being compliant with the EU environmental normative aimed at reducing CO2 emissions. The Gela refinery is located on the Southern coast of Sicily. The refinery was shut-down in March 2014 and in November 2014, Eni signed a Memorandum of Understanding for the reconversion of the plant into a bio-refinery with the Italian Ministry for Economic Development and Local Authorities. In 2017 Eni's activities continued in line with the commitments foreseen in the Memorandum of Understanding. In August 2017 the project obtained the environmental impact assessment and authorization (VIA/AIA) by the Italian Ministry of the Environment and the Ministry of Cultural Heritage. The project is expected to come on stream by the end of 2018. The refinery will have a capacity of 750 ktonnes/y. The conversion will leverage on the application of the Eco-fining proprietary technology, developed and licensed by Eni, to convert unconventional and second generation raw materials into green diesel, a highly sustainable biofuel. The plant properties will allow the production of green diesel in compliance with the last regulatory constraints in terms of reduction of GHG emissions throughout the whole production chain, deploying the full capacity in process second-generation feedstock.

TABLE OF CONTENTS

The table below sets forth Eni's products availability figures for the periods indicated.

Availability of refined products	2017	2016	2015
	(mmtonnes)		
ITALY			
Refinery throughputs			
At wholly-owned refineries	16.03	17.37	18.37
Less input on account of third parties	(0.34)	(0.27)	(0.38)
At affiliated refineries	5.46	4.51	4.73
Refinery throughputs on own account	21.15	21.61	22.72
Consumption and losses	(1.36)	(1.53)	(1.52)
Products available for sale	19.79	20.08	21.20
Purchases of refined products and change in inventories	6.74	6.28	6.22
Products transferred to operations outside Italy	(0.46)	(0.39)	(0.48)
Consumption for power generation	(0.34)	(0.37)	(0.41)
Sales of products	25.73	25.60	26.53
Green refinery throughputs	0.24	0.21	0.20
OUTSIDE ITALY			
Refinery throughputs on own account	2.87	2.91	3.69
Consumption and losses	(0.22)	(0.22)	(0.23)
Products available for sale	2.65	2.69	3.46
Purchases of finished products and change in inventories	4.36	4.72	4.77
Products transferred from Italian operations	0.46	0.40	0.48
Sales of products	7.47	7.81	8.71
Refinery throughputs on own account	24.02	24.52	26.41
of which: refinery throughputs of equity crude on own account	3.51	3.43	5.04
Total sales of refined products	33.20	33.41	35.24
Crude oil sales	0.86	0.20	0.27
TOTAL SALES	34.06	33.61	35.51

In 2017, refining throughputs were 24.02 mmtonnes, down by 2% from 2016 due to to the downtime of some plants at Sannazzaro refinery and the shutdown at the Taranto refinery, partly offset by a better performance of Milazzo and Livorno refineries.

Outside Italy, Eni's refining throughputs were 2.87 mmtonnes, down by 40 ktonnes or 1.4% due to the downtime of BayernOil refinery in 2017, more impacting compared to the downtime of PCK refinery in 2016.

Total throughputs in wholly-owned refineries were 16.03 mmtonnes, down by 1.34 mmtonnes or 7.7% compared with 2016.

Approximately 15.2% of processed crude was equity, increased approximately 0.4 percentage points from 2016 (14.8%).

Logistics

Eni is a leading operator in the Italian oil and refined products storage and transportation business.

It owns an integrated infrastructure consisting of 16 directly managed depots and a network of oil and refined products pipelines. Eni logistic model is organized in three hubs (North, Central and South Italy). These hubs manage the product flows in order to guarantee high safety and technical standards, as well as cost effectiveness. Eni is also in joint venture with other Italian operators to optimize its logistic footprint and increase efficiency. Other depots are operated by six different joint ventures (Sigemi, Petroven, Petra, Seram, Disma, Toscopetrol). Eni transports oil and refined products: (i) by sea through spot and long-term contracts of tanker ships; and (ii) through a proprietary pipeline network extending approximately 1,462 kilometers.

Secondary distribution to retail and wholesale markets is outsourced to independent tanker carriers, selected as market leaders in their own field.

Marketing

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

TABLE OF CONTENTS

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

Oil products sales in Italy and outside Italy	2017	2016	2015
	(mmtonnes)		
Italy			
Retail	6.01	5.93	5.96
Wholesale	7.64	8.16	7.84
	13.65	14.09	13.8
Petrochemicals	0.86	1.02	1.17
Other sales	11.22	10.49	11.56
Total	25.73	25.60	26.53
Outside Italy			
Retail	2.53	2.66	2.93
Wholesale	3.48	3.61	4.26
	6.01	6.27	7.19
Other sales	1.46	1.54	1.52
Total	7.47	7.81	8.71
TOTAL SALES	33.20	33.41	35.24

In 2017, sales volumes of refined products (33.20 mmtonnes) were down by 0.21 mmtonnes or by 0.6% from 2016, mainly due mainly due to the decrease of wholesale sales in Italy and the assets disposal in Hungary and Slovenia in the second half of 2016.

Retail sales in Italy

In 2017, retail sales in Italy were 6.01 mmtonnes, with a slight increase compared to 2016 (about 80 ktonnes from 2016 or 1.3%). Average gasoline and gasoil throughput (1.588 kliters) increased by approximately 40 kliters from 2016. Eni's retail market share in 2017 was 25%, up by 0.7 percentage points from 2016 (24.3%).

As of December 31, 2017, Eni's retail network in Italy consisted of 4,310 service stations, lower by 86 units from December 31, 2016 (4,396 service stations), resulting from the release of low throughput stations (25 units) and negative balance of acquisitions/releases of lease concessions (56 units) and of motorway concessions (5 units).

Retail sales in the rest of Europe

Eni's strategy in the rest of Europe is focused on selectively growing its presence, particularly in Germany and Austria leveraging on the synergies ensured by the proximity of these markets to Eni's production and logistic facilities.

In 2017, retail sales of refined products in the rest of Europe (2.53 mmtonnes), recorded a reduction from 2016 (down by 4.9%). This result reflected mainly the assets disposal in Slovenia and Hungary in the second half of 2016. On a homogeneous basis, when excluding the impact of the above mentioned disposal, sales slightly increased by 1.1% due to higher volumes traded in Austria and Germany.

At December 31, 2017, Eni's retail network in the Rest of Europe consisted of 1,234 units, increasing by 8 units from December 31, 2016, mainly in Germany. Average throughput (2,440 kliters) increased by 100 kliters compared to 2016 (2,340 kliters).

Other businesses

Wholesale

Eni is strongly present in wholesale market in Italy, including sales of diesel fuel for automotive use and for heating purposes, for agricultural vehicles and for vessels and sales of fuel oil. Major customers are resellers, agricultural users, manufacturing industries, public utilities and transports, as well as final users

TABLE OF CONTENTS

(transporters, condominiums, farmers, fishers, etc.). Eni provides its customers with its expertise in the area of fuels with a wide range of products that cover all market requirements. Customer care and product distribution are supported by a widespread commercial and logistical organization presence throughout Italy and is articulated in local marketing offices and a network of agents and concessionaires.

In 2017, sales volumes on wholesale markets in Italy (7.64 mmtonnes) decreased by 0.52 mmtonnes or 6.4% from the previous year, mainly due to lower volumes marketed of gasoil, bunkering and fuel oil partly offset by higher sales of jet fuel and bitumens.

Wholesale sales in the Rest of Europe were 3.03 mmtonnes, down by 4.7% from 2016 due to lower sold volumes in Austria and France and the above-mentioned asset disposals in the East Europe, offset by higher volumes in Switzerland and Germany.

Supplies of feedstock to the petrochemical industry (0.86 mmtonnes) decreased by 15.7%. Other sales in Italy and outside Italy (12.68 mmtonnes) decreased by approximately 0.65 mmtonnes or 5.4%, mainly due to lower sales volumes to oil companies.

LPG

The marketing of LPG in Italy is supported by the refining production and a logistic network made up of five bottling plants, 1 owned storage site and coastal storage sites located in Livorno, Naples and Ravenna.

LPG is used as heating and automotive fuel. In 2017, Eni share of LPG market in Italy was 17.7%.

Outside Italy, the main market of Eni is Ecuador, with a market share of 37.9%.

Lubricants

Eni operates six (owned and co-owned) blending and filling plants, in Italy, Spain, Germany, USA, Africa and in the Far East. With a wide range of products composed of over 650 different blends Eni masters international state of the art know how for the formulation of products for vehicles (engine oil, special fluids and transmission oils) and industries (lubricants for hydraulic systems, industrial machinery and metal processing). In Italy, Eni is leader in the manufacture and sale of lubricant bases, manufactured at Eni’s refinery in Livorno. Eni also owns one facility for the production of additives in Robassomero.

In 2017, Eni’s share of lubricants market in Italy was 19.58%, in Europe 3% and on a worldwide base 0.6%. Eni operates in more than 80 countries by subsidiaries, licensees and distributors.

Oxygenates

Eni’s, through its subsidiary Ecofuel (100% Eni’s share), sells approximately 1 mmtonnes/y of oxygenates, mainly ethers (approximately 3% of world demand, used as a gasoline octane booster) and methanol (mainly for petrochemical use). About 85% of oxygenates are produced in Eni’s plants in Italy (Ravenna), Saudi Arabia (in joint venture with Sabic) and Venezuela (in joint venture with Pequiven) and the remaining 15% is purchased.

Chemicals

Eni operates in the businesses of olefins and aromatics, basic and intermediate products, polystyrene, elastomers and polyethylene. Its major production hubs are located in Italy and Western Europe. At the end of 2017 Eni started operations for the production of elastomers in South Korea in joint venture with a local operator.

The business results of operations in 2017 and its strategy are described in Item 5 – 2015-2017 Group results of operations and Item 5 – Management’s expectations of operations.

In 2017 sales of chemical products amounted to 3,712 ktonnes, slightly decreased from 2016 (down by 47 ktonnes, or 1.3%). The steepest declines were registered in olefins (down by 7.1%) and derivatives (down by 14.1%), partly offset by higher sales volumes of polyethylene (+10.8%).

TABLE OF CONTENTS

Average unit sales prices increased by 16% from 2016. The intermediates business up by 27%, in particular butadiene (up by 88.3%) and the polymers business up by 13%, reflecting styrene and elastomers prices increased (up by 14.8% and 24.1%, respectively).

Petrochemical production of 5.818 ktonnes increased by 172 ktonnes (up by 3%) mainly due to higher production of polyethylene (up by 14.6%) and elastomers businesses (up by 5.9%); the intermediates productions were slightly increased (+1,2%).

The main increases in production were registered at the Ragusa site (up by 90%), due to a recovery of production capacity for a malfunctioning occurred at the plant in 2016, as well as Ravenna and Dunkerque (olefins), and Ferrara and Mantova sites (styrene) due to fewer production shutdowns of the plants. Decreasing productions at the Marghera, Mantova (derivatives) and Dunastyr sites due to planned shutdowns of the plants.

Nominal capacity of plants is in line from the previous year. The average plant utilization rate calculated on nominal capacity was 72.8% increased from 2016 (71.4%).

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

	Year ended December 31,		
	2017	2016	2015
	(ktonnes)		
Intermediates	3,458	3,417	3,334
Polymers	2,360	2,229	2,366
Total production	5,818	5,646	5,700
Consumption and losses	(2,584)	(2,166)	(1,908)
Purchases and change in inventories	478	279	9
	3,712	3,759	3,801

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

	Year ended December 31,		
	2017	2016	2015
	(€ million)		
Intermediates	1,988	1,688	1,899
Polymers	2,730	2,380	2,690
Other revenues	133	128	127
Total revenues	4,851	4,196	4,716

Intermediates

Intermediates revenues (€1,988 million) increased by €300 million from 2016 (up by 17.8%) reflecting the higher commodity prices scenario that influences average intermediates prices of the main product of the business Unit. Sales decreased by 7.6%, in particular for ethylene business (down by 16%) and derivatives (down by 14.1%) driven by the planned shutdowns of Mantova plants.

Average unit prices increased by 27.1%, in particular olefins (up by 25.8%), aromatics (up by 29.2%) and derivatives (up by 26.7%).

Intermediates production (3,458 ktonnes) registered an increase of 1.2% from the last year. Increasing of olefins (up by 4.3%) and reduction of derivatives (down by 11.2%).

Polymers

Polymers revenues (€2,730 million) increased by €350 million or 14.7% from 2016 thanks to higher sales volumes (up by 6%), as well as to the increase of the average unit prices (up by 13%).

The styrenics business benefited from high commodities prices (styrene) with an increase of average sold prices (up by 14.8%); slightly decrease of sold volumes (down by 2%).

Polyethylene volumes increased (up by 8.3%) and average prices recorded a decrease (down by 2.2%).

TABLE OF CONTENTS

Polymers productions increased by 5.9% (2.360 ktonnes) from 2016 mainly driven by higher production of polyethylene (up by 14.6%). Elastomers business productions increased (up by 5.9%), especially in BR rubbers (up by 12.4%) and EPDM (up by 25.1%). The styrenics business reported higher production of expandable polystyrene (up by 6%) and ABS/SAN (up by 17.9%), decreasing production of styrene (down by 5.9%) due to planned shutdowns of the Mantova plant.

Capital expenditures

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

Corporate and Other activities

These activities include the following businesses:

- the "Other activities" segment comprises results of operations of Eni's subsidiary Syndial which runs reclamation and decommissioning activities pertaining to certain businesses which Eni exited, divested or shut down in past years, as well as Eni New Energy SpA which engages in developing the business of renewable energy; and

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

Seasonality

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

Research and development

Technology research and development (R&D) and continuous innovation are key factors in successfully implementing Eni's business strategies and in supporting mid and long-term performances. R &D continuously supports the core business through the development of technologies able to reduce risks and maximize operational efficiency.

Eni recognizes the need to limit the rise in global temperature, by the end of the century, below 2° C compared to pre-industrial levels and intends to play a leadership role in the process of energy transition towards a low-carbon future. In this context, R&D represents a key element for the transformation of Eni into an integrated energy company and is committed to develop new solutions in the renewable energy sector, to support the Green Refinery, and to promote a progressive decarbonization of the energy mix through the fostering of the use of natural gas also through new business opportunities.

In order to address the several challenges that energy industry will have to face, Eni will therefore pursue the following technological targets in the next future:

TABLE OF CONTENTS

- reducing operational risk and maximizing operational efficiency by development of new tools for prevention and response to blow outs (mechanical barriers and equipment for the capture of subsea oil eruption) and development of tools for vessel maintenance and restoring clogged pipes;
- strengthening technological leadership in exploration by continuously development of proprietary tools;
- maximizing the recovery factor of reservoirs aiming at innovative enhanced oil recovery techniques sustainable also in low oil price scenarios;
- further development of technologies for the production of energy from renewable sources, in particular solar thermal and organic photovoltaic and quickly transfer them to the Energy Solution business unit;
- integrating renewable sources with upstream operations especially in off-grid locations;
- focusing on solar systems that use less polluting materials, can produce at lower cost and are more easily integrated into buildings;
- further development of Eni's Green Refinery processes with innovative solution for feeding bio-refineries with other feedstock than palm oil;
- formulating innovative fuels and lubricants that comply with European regulations and new motor specifications;
- development of new technologies for the separation, conversion, transportation and utilization of natural gas;
- further development of innovative environmental technologies for in situ monitoring and remediation.

In 2017, Eni filed 27 patent applications (40 in 2016).
In 2017, Eni's overall expenditure in R&D amounted to €185 million which were almost entirely expensed as incurred (€161 million in 2016 and €176 million in 2015).

Exploration & Production

Digital rock physics. An innovative workflow for petrophysical characterization was developed in 2017, integrating a new powerful X-ray micro CT (Computed Tomography) with SEM (Scanning Electron Microscope) images and dynamic simulation at pore/core scale; it can be applied to the majority of reservoir rock types, allowing a much faster petrophysical characterization. The next development phase will include static and dynamic simulations at core scale in order to calculate petrophysical properties like porosity, absolute and relative permeability.

New fluid for cementing operations. Eni and Versalis developed and scaled up an advanced fluid to clean up casings and wellbores with the objective of substantially improving cementing operations. The main benefit is an improved cement adhesion on casing and subterranean formations, with higher well integrity.

Drilling automation. Two new tools addressing lost/non productive time and based on big data technology were developed in 2017 to support operations. The first tool is e.NPT (Eni Non Productive Time) which analyzes and integrates multiple data sources in real time in order to predict sticking events. The second tool is a new solution enabling a near real time performance analysis to identify Invisible Lost Times.

Drilling Safety Technologies. The project aims to reduce by two orders of magnitude the risk of blowout occurrence compared to the OGP reference. To achieve this goal, new technologies able to improve well integrity both during drilling and well productive life are being developed. In 2017 Eni has field-tested the functionality and the integrity of the Downhole Isolation Packer. The tool, composed by a packer and a bypass valve, provides a backup barrier to ensure the control of formation fluids at all times.

Subsea R&D Program: in 2017 Eni launched a program to develop, together with industry partners, technologies to significantly reduce subsea development CAPEX and OPEX by using full subsea architectures, very long step-outs and life-of-field robotics. The program starts from lessons learned from Eni's most recent subsea development projects (started-up in the last 3 years). The objective is to increase the distance between new subsea production systems and existing floating production facilities, or connect

TABLE OF CONTENTS

those new subsea assets directly to shore. Cost effective and flexible extra-long subsea architectures prove to efficiently work on a wide range of applications and design basis parameters. Key enabling technologies under development are multicontrol communication, subsea power distribution, subsea boosting and thermal management.

Refining & Marketing

Biofeedstock database. In 2017 Eni created one of the first Ecofining biofeedstock database in the oil industry. The archive already includes more than 100 characterized bio-oils from all over the world, representing possible alternatives to palm oil for our biorefining. The database is utilized to optimize the supply chain to reduce costs.

Methanol based alternative fuels. A new gasoline formulation containing alternative fuels (15% methanol and 5% bioethanol comprising a proper additive package to protect the engine), labeled M15, has been developed and is currently undergoing extensive road tests on five Fiat 500 cars belonging to the car sharing Enjoy fleet in Milan. M15 can provide more than 3% CO_2 tailpipe emissions reduction due to the lower H/C ration and higher octane number.

Eni Green Diesel+. On 18 October, Eni successfully presented the final result of an experimental activity agreed with the Mayor of Turin, showing the environmental advantages of Eni Diesel+ on old buses (Euro 3) of Turin’s Transport Company (GTT): lower particles number (-40%), fewer particulate matter (-16%), compared to commercial diesel fuel; also NO_x and CO_2 emissions are reduced.

i-Sigma Bio Tech lubricants. Eni R&D in collaboration with Versalis and Matrìca developed a new synthetic lubricant base stock of ester type, obtained from renewable sources. This synthetic product is featured with excellent properties in terms of oxidation stability, volatility and wear protection that are suitable for several applications in the industrial and automotive lubrication sectors. Bioester is a key component of a new SAE 10W-30 engine oil for heavy duty services (trucks, buses, and off-road vehicles) designed and tested by Eni to meet some important international technical specifications, and ready for the market under the brand name i-Sigma Bio Tech.

Energy Saving Lubricants: In collaboration with BHGE, Eni has developed an innovative low viscosity oil for turbomachinery sector, Eni OTE GT 15, that showed outstanding energy saving characteristics by reducing friction losses up to 15%, decreasing the consumption of natural gas and decreasing CO_2 emissions. In 2017 Eni OTE GT 15 received the letter of approval by BHGE and is now commercially available.

Renewable Energy & Environment

Concentrated Solar Power. The Eni R&D effort towards the definition and application of improved Concentrated Solar Power (CSP) solutions has led to proprietary technology assemblies with advantageous capital investment and operation costs. A long-term partnership with Massachusetts Institute of Technology and the Politecnico of Milano (that has realized the first proprietary CSP prototype) has allowed the focusing of capabilities for this purpose. The deployment phase is ongoing in the South of Italy, and foreseen in North Africa, Middle East and other suitable areas around the globe.

Luminescent Solar Concentrators and Smart Windows. The possibility of producing partially transparent window devices allowing the transfer of some of the incoming solar radiation towards photovoltaic modules on their sides has allowed the design and commercialization of Smart Window solutions. These produce relevant energy savings for conditioning purposes and electric energy production for small applications. Eni’s Luminescent Solar Concentrator technology is at the core of these devices and other smart applications are currently being explored. To this purpose, in 2017, an agreement with one of the major European building systems company was established. An extensive commercialization phase will begin at the end of 2018.

Organic Photovoltaic. New solutions (active and buffer materials) for flexible solar cells have been developed and applied in an emerging field that relies on organic polymeric photovoltaic solutions. The developed technology solutions allow easy transportation and application wherever power is required and no grid infrastructure is available. Thanks to the light weight and the technical and operational simplicity some photovoltaic modules with inflatable support have been also developed and installed in demonstrative situations.

TABLE OF CONTENTS

Energy storage. The storage of the electric energy produced from renewable sources is indeed a key issue for allowing the further development of this field. Accordingly, Eni is testing solutions for Redox Flow Batteries and for integrating these devices "conventional" electrical energy production devices such as gas turbines and diesel generators in demonstrative plants for off-grid applications. Targeting in these cases a relevant CO_2 (higher that 75%) emission reduction.

Phytoremediation. Field tests showed that selected Plant Growth-Promoting Rhizobacteria able to enhance the plants biomass, increasing the uptake of metallic soil contaminants. The usage of these bacteria has been experimented in field tests for promoting the biodegradation of hydrocarbons in polluted environments (Ravenna, Priolo and Mantova).

Hydrocarbon recovery. Eni developed and applied a proprietary technology (e-hyrec®) allowing the remediation of aquifer environments through the recovery and separation of hydrocarbon contaminants. The technology tested at the refinery site in Gela (Italy) is now under application in several fields. An agreement with a manufacturer operating in the water treatment sector has been established with the purpose of deploying the technology in 2017. The full commercialization phase will begin in the second quarter of 2018.

Soil and Groundwater Bioremediation: Eni R&D has developed through laboratory, pilot and field scale tests, technologies and site-specific protocols (e-lamina®) for treating contaminated soils and groundwater utilizing biological, environmental-friendly and cost-effective means. The protocols involve: (i) sampling and site characterization, (ii) evaluation of the bio-degradation potential by micro/meso-cosm test studies, (iii) in situ pilot plant activities, (iv) design and application of full-scale bio-remediation treatments.

Waste to Fuel. Eni is evaluating a Waste-to-Fuel process able to transform wet domestic waste into bio-oils suitable to feed Eni's biorefineries to obtain second-generation biofuels. The pilot scale development phase of the technology has been completed.

Hybridization of Hydrogen production/utilization for the mobility/fuel sector. The Hydrogen molecule can be produced from several sources including, gaseous hydrocarbons and renewable sources such as bio-mass derived compounds, municipal solid wastes and electrolysis of water utilizing electric energy produced by renewable sources. The "renewable" and the hydrocarbon produced hydrogen can be utilized in the mobility sector directly as fuel in Fuel Cell vehicles or integrated in the refinery hydro-treating processes for producing advanced hydrocarbon fuels. In this sense the production/utilization of Hydrogen allows a full integration of renewable and hydrocarbon refinery pathways for improving the sustainability of the mobility and fuel production sectors.

Energy Transition

In 2016 Eni launched the "Energy Transition" R&D program with the aim of developing new technologies to promote the widespread use of natural gas, making easier its production and transport, widening its uses and favoring the decarbonization of the whole value chain. In particular, the research deals with three areas of interest:

a) Natural gas transportation, transformation and uses,

b) H_2S management,

c) CO_2 management.

On the forefront of Natural Gas transportation and conversion, important results have been obtained for the development of a process for the production of methanol from natural gas. The process is based on an Eni proprietary technology for the conversion of methane to syngas, which is cheaper and has a footprint and a weight much lower than the existing processes based on steam reformer.

In the area of H_2S and CO_2 capture, innovative highly effective solvents for the separation of H_2S and CO_2 from natural gas have been identified and tested at lab scale. Now the results is under scaling-up to a pilot unit with the cooperation of an external specialized company. New ways for sulphur utilization are under consideration. Innovative sulphur-based products which can be used in agriculture have been obtained and are under testing in a field parcel in

Central Italy.

TABLE OF CONTENTS

Concerning CO_2 management, the project about on-board CO_2 capture from autovehicles, launched in 2016 with the close collaboration of MIT, has generated interesting results and new patents. Since 2017 Fiat-Chrysler-Automobiles has joined the project, whose goal has been extended to the construction of a demonstration vehicle equipped with on-board CO_2 capture system by the spring 2019. The target for the first demonstration unit is for a 25% capture of the total CO_2 emitted by the internal combustion engine that is stored in liquid phase in a dedicated on-board tank. Innovative uses for CO_2 are also under investigation. Promising materials, which could be employed in the building and construction industry have been obtained by "CO_2 mineralization", as well as polymers with high CO_2 content.

Petrochemicals

Guayule. Project aiming at the production of natural latex, dry rubber and resins from Guayule (ongoing experimental cultivation in Basilicata and Sicily) with exploitation of all components with proprietary technologies and their development in the market allowing the use of whole value of the Guayule plant.

An important agreement has been signed with one of the most important international player in the field of tire manufacturing for the joint development of a common technology platform for guayule production and applications.

Bio-butadiene. A joint venture between Versalis and Genomatica has developed a process to produce 1,3 bio-butadiene from renewable sources via sugars production from biomasses, fermentation and subsequent chemical processes.

Insurance

In order to control the insurance costs incurred by each of Eni's business units, the Company constantly assesses its risk exposure in both Italian and foreign activities. The Company has established a captive subsidiary, Eni Insurance DAC, in order to efficiently manage transactions with mutual entities and third parties providing insurance policies. Internal insurance risk managers work in close contact with business units in order to assess potential underlying business and other types of risks and possible financial impacts on the Group results of operations and liquidity. This process allows Eni to accept risks in consideration of results of technical and risk mitigation standards and practices, to define the appropriate level of risk retention and, finally, the amount of risk to be transferred to the market. Eni enters into insurance arrangements through its shareholding in the Oil Insurance Ltd (OIL) and with other insurance partners in order to limit possible economic impacts associated with damages to both third parties and the environment occurring in case of both onshore and offshore accidents. The main part of this insurance portfolio is related to operating risks associated with oil&gas operations which are insured making use of insurance policies provided by the OIL, a mutual insurance and re-insurance company that provides its members with a broad coverage of insurance services tailored to the specific requirements of oil and energy companies. In addition, Eni uses insurance companies who it believes are established in the marketplace. Insured liabilities vary depending on the nature and type of circumstances; however, underlying amounts represent significant shares of the plafond granted by insuring companies. In particular, in the case of oil spills and other environmental damage, current insurance policies cover costs of cleaning-up and remediating polluted sites, damage to third parties and containment of physical damage up to $1.2 billion for offshore events and $1.4 billion for onshore plants (refineries). These are complemented by insurance policies that cover owners, operators and renters of vessels with the following maximum amounts: $1,250 million for the fleet owned by the subsidiary LNG Shipping in the Gas & Power segment and time charters; $1 billion for FPSOs used by the Exploration & Production segment for developing offshore fields.

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

Environmental matters

Environmental regulation

Eni is subject to numerous EU, international, national, regional and local environmental, health and safety laws and regulations concerning its oil&gas operations, products and other activities, including

TABLE OF CONTENTS

legislation that implements international conventions or protocols. In particular, exploration, drilling and production activities require acquisition of a special permit that restricts the types, quantities and concentration of various substances that can be released into the environment. The particular laws and regulations can also limit or prohibit drilling activities in the certain protected areas or provide special measures to be adopted to protect health and safety at workplace and health of communities that could have been affected by the Company’s activities. These laws and regulations may also restrict emissions and discharges to surface and subsurface water resulting from the operation of natural gas processing plants, petrochemical plants, refineries, pipeline systems and other facilities that Eni owns. In addition, Eni’s operations are subject to laws and regulations relating to the production, handling, transportation, storage, disposal and treatment of waste materials. Environmental laws and regulations have a substantial impact on Eni’s operations. Some risk of environmental costs and liabilities is inherent in certain operations and products of Eni, and there can be no assurance that material costs and liabilities will not be incurred. See “Item 3 – Risk factors”.

We believe that the Company will continue to incur significant amounts of expenses in order to comply with pending environmental, health and safety protection and safeguard regulations, particularly in order to achieve any mandatory or voluntary reduction in the emission of GHG in the atmosphere and cope with climate change and water quality of discharges, as well as availability.

European Union Environmental Laws Framework

In 2017, the main environmental efforts of the European Union continued to focus on the air quality, energy transition, circular economy, clean mobility, energy efficiency and climate change.

On November 4, 2016, the Paris Agreement entered into force, exactly 30 days after the date on which the last of at least 55 Parties to the Convention accounting in total for at least an estimated 55% of the total global greenhouse gas emissions have deposited their instruments of ratification. To date, the 175 Parties have ratified the Convention. This important step in the common international Climate Change strategy sets out a global action plan to put the world on track to avoid dangerous climate change by limiting global warming to well below 2°C. By the ratification of the Convention, the governments agreed to limit the increase to 1.5°C, since this would significantly reduce risks and the impacts of climate change. In 2017, the UN Climate Change Conference (COP 23) had taken place in Bonn. The COP 23 was the next step for governments to implement the Paris Agreement and accelerate the transformation to sustainable, resilient and climate-safe development. This conference further clarified the enabling frameworks that will make the agreement fully operational and the support needed for all nations to achieve their climate change goals. The participated countries had continued to negotiate the finer details of how the agreement will work from 2020 onwards. In particular the “Talanoa Dialogue” was proposed and the a large group of participate states (among them also Italy, Denmark, Finland) have joined the “Powering Past Coal Alliance” declaring “analysis shows that coal phase-out is needed no later than by 2030 in the OECD and EU28, and no later than by 2050 in the rest of the world”.

On October 4, 2016, the European Parliament approved the ratification of the Paris Agreement by the European Union. The Paris Convention vindicates the EU strategy in climate change defined in October 2014, when the European Council agreed on the 2030 climate and energy policy framework. In this strategy the EU stated an ambitious economy-wide domestic target of at least 40% GHG reduction for the period up to 2030 (below 1990 levels) and to a 27% share of renewable energy in final energy consumption.

On November 30, 2016, the following step of this strategy was written down, when the EU Commission presented the Clean Energy for All Europeans (so called “Clean Energy Package”). By this proposal, the EU is consolidating the enabling environment for the transition to a low carbon economy through a wide range of interacting policies and instruments reflected under the Energy Union Strategy. The Package has three main goals: putting energy efficiency first, achieving global leadership in renewable energies and providing a fair deal for consumers. The Package includes a proposal to revise Directive 2012/27/EU on Energy Efficiency (EED) with the goal to adapt the existing Directive in order to meet EU climate and energy targets for 2030 and align it with other aspects of the Clean Energy package, including a revised Energy Performance of Buildings Directive (EPBD), a recast directive on the Promotion of Renewable Energy Sources – Directive 2009/28/CE (RED II) and a new regulation on Governance of Energy Union. The latest progresses were made during the plenary session of the European parliament on the 17th January 2018, the outcome was not exactly in line with the position expressed by the commission

TABLE OF CONTENTS

one month earlier. The agreement is to be found for the targets to be achieved by 2030: binding EU-level targets of 35% improvement in energy efficiency; a minimum 35% share of energy from renewable sources in gross final consumption of energy (vs. a previous proposal of just 27%); and a 12% – 14% share of energy from renewable sources in transport. To meet these overall targets, EU member states are asked to set their own national targets, to be monitored and achieved in line with a draft law on the governance of the Energy Union. The contribution of so-called “first generation” biofuels (made from food and feed crops) should be capped, according to the parliament proposal to 2017 levels, with a maximum of 7% in road and rail transport as well has been considered a complete phase out of palm oil in transport fuels by 2021 No bans of palm oil is foreseen according to the EU commission position. On the other hand, the development of second generation biofuels is expected with 1.5% target at 2021 and 10% at 2030. EU Council, Commission and parliament are expected to find a common position the soonest, since the legislative process on the Clean Energy Package is expected to be completed by the end of 2018. For Eni’s strategies and policy on biofuels, a revision of RED has a particular importance.

Moreover, under the energy market reform, in February 2018 MEPs have decided to impose rules on mechanisms often used as coal power subsidies, voting in favor of strict conditions for so-called capacity mechanisms, which will no longer be eligible for subsidies as of 2020 for new infrastructure and as of 2025 for existing plants. The Commission’s proposal that suggested excluding any plants that emit more than 550g of CO2 per kwh from public money, emerged as one the main points of the EU climate legislation. The 550g criterion, uses in the European Investment Bank’s policy, is technology neutral and in practice preclude coal power plants and some inefficient gas plants. It faced heavy opposition from coal-dependent member states like Poland in a recent Energy Council and will be discussed during upcoming negotiations.

A centerpiece of the EU’s 2030 energy and climate policy framework is the binding target to reduce overall GHG emissions by at least 40% below 1990 levels by 2030. To achieve this cost-effectively, the sectors covered by the EU Emission Trading System (ETS) will have to reduce their emissions by 43% compared with 2005, while non-ETS sectors will have to reduce theirs by 30%. The ETS is now in the last years of the III phase (2013-2020). In July 2015, the European Commission published its proposal to revise the directive on the EU ETS for the 2021-2030 period (Phase IV) and on February 2018, the European Council formally approved the reform of the EU ETS for phase IV to ensure the energy sector and energy intensive industries deliver the emissions reductions needed. To this end, the overall number of emission allowances will decline at an annual rate of 2.2% from 2021 onwards, compared to 1.74%. Currently around 48% of Eni’s direct GHG emissions are included within the Carbon Pricing Scheme by its participation in the EU ETS.

On 21 December, representatives of the Estonian Presidency and the European Parliament reached a provisional deal on the effort sharing regulation to ensure further emission reductions in sectors falling outside the scope of the EU emissions trading system (ETS) for the period 2021-2030. In January 2018, EU ambassadors gave their support to the provisional agreement. The text has now to be approved by the European Parliament. This agreement brings the EU closer to fulfilling its Paris climate commitment of an at least 40% cut in greenhouse gas emissions by 2030 compared to 1990 levels. The regulation aims to ensure that the non-ETS sectors emissions reduction target of 30% by 2030 compared to 2005 levels is reached in the effort sharing sectors, including buildings, agriculture (non-CO2 emissions), waste management and transport (excluding aviation and international shipping).

Air quality remains at the center of the European environmental policies and strategies. On December 18, 2013, the European Commission adopted a package of proposals to improve air quality in the EU, which updated the air policy objectives for 2020 and 2030. The package includes a long-awaited revision of the National Emission Ceilings (NEC) Directive, a proposal to address emissions from medium scale combustion plants (MCP) and a proposal for ratification of the recently amended Gothenburg Protocol.

In order to guarantee better quality standards and to shift toward a low carbon economy, in December 2017, the Commission has launched the Clean Mobility Package. This is a decisive step forward in implementing the EU’s commitments under the Paris Agreement for a binding domestic CO2 reduction of at least 40% till 2030. Its aim is to help accelerate the transition to low- and zero emissions vehicles, through a new target for the EU fleet wide average CO2 emissions of new passenger cars and vans of 30% by 2030 to provide stability and long-term direction. The Mobility Package has a 2025 intermediary target of 15% to ensure that investments kick-start already now. As the confirmation of Eni’s involvement in sustainable mobility in November Eni and FCA have signed a contract to carry out research and develop technological applications aimed at reducing CO2 emissions in road transport.

TABLE OF CONTENTS

On December 31, 2016, the new National Emissions Ceilings (NEC) Directive entered into force. The NEC directive based on a Commission proposal sets stricter limits on the five main pollutants in Europe: sulfur dioxide (SO2), nitrogen oxides (NOx), ammonia (NH3), volatile organic compounds (VOC) and primary particulate matter (PM). The NEC Directive must be transposed by the Member states by 30 June 2018. The new NEC directive repeals and replaces Directive 2001/81/EC. Each EU Member State is required to produce a National Air Pollution Control Program by 31 March 2019 setting out the measures it will take to ensure compliance with the 2020 and 2030 reduction commitments.

On December 18, 2015, the Directive No. 2015/2193/EU on the limitation of emissions of certain pollutants into the air from medium combustion plants entered into force. The Medium Combustion PlanT Directive (MCP Directive) regulates pollutant emissions from the combustion of fuels in plants with a rated thermal input equal to or greater than 1 MW and less than 50 MW. The MCP Directive is a part of the Clean Air Policy Package adopted on December 18, 2013 and it regulates emissions of SO2, NOX and dust into the air with the aim of reducing those emissions and the risks to human health and the environment they may cause. The MCP Directive will have to be transposed by Member States by December 19, 2017. The MCP Directive also ensures implementation of the obligations arising from the Gothenburg Protocol under the UNECE Convention on Long-Range Trans-boundary Air Pollution.

The Industrial Emission Directive (IED) 2010/75/EU is fundamental for European industries, it provides the framework for granting permits for about 50,000 industrial installations across the EU. It lays down rules on the integrated prevention and control of air, water and soil pollution arising from industrial activities. As part of the IED framework, additional emission limit values are defined by the sector specific and cross-sector Best Available Technology (BAT) Conclusions.

In 2016, the Commission has published the Implementing Decision (EU) 2016/902 of 30 May 2016 establishing best available techniques (BAT) conclusions, under Directive 2010/75/EU, for common wastewater and waste gas treatment/management systems in the chemical sector.

In August 2017 the Commission Implementing decision 2017/1442 of 31 July 2017 entered in force. The decision establishes the best available techniques (BAT) conclusions, under Directive 2010/75/EU of the European Parliament and of the Council, for large combustion plants (LCP – combustion installations with a rated thermal input exceeding 50 MW). Plants with a thermal input lower than 50 MW are, however, discussed in the LCP BAT where technically relevant because smaller units can potentially be added to a plant to build one larger installation exceeding 50 MW. In December 2017, the Large Combustion Plant Best Available Technique reference document (LCP BREF) was published. The update of both documents was expected under the Emission Directive and will have a significant implication on the Eni's technologies applied in the power plants. A Technical Working Group has been formed to implement a new Best Available Techniques Guidance Document on the upstream hydrocarbon exploration and production sector. Moreover, in November, Commission has published its implementing decision establishing best available techniques (BAT) conclusions, under Directive 2010/75/EU of the European Parliament and of the Council, for the production of large volume organic chemicals (LVOC BAT). New emissions and efficiency standards will help national authorities to lower the environmental impact of the 3,200 installations that produce Large Volume Organic Chemicals (LVOC) and represent 63% of the EU's entire chemical industry.

In 2017 (at the latest on May 16) all Member States must apply the rules of the new Environmental Impact Assessment Directive 2014/52/EU (EIA). The EIA Directive should simplify the rules for assessing the potential effects of projects on the environment and boarders scope of the EIA covering new issues such as climate change, biodiversity, resource efficiency and risks prevention on both human and environmental aspects.

Fluorinated gases ('F-gases') play an important role in the accomplishment of the Paris Agreement and in the EU environmental policy. These ozone-depleting substances are regulated by F-gas Regulation (No. 517/2014) which applies from January 1, 2015. The new regulation strengthens the previous measures and should cut by 2030 the EU's F-gas emissions by two-thirds compared with 2014 levels. This represents a fair and cost-efficient contribution by the F-gas sector to the EU's objective of cutting its overall GHG emissions by 80-95% of 1990 levels by 2050. In 2017, the EU continued to shape the F-gases strategy. In October 2017, the Commission Implementing Decision (EU) 2017/1984 was published in the Official Journal. The decision sets a reference values for the period 1 January 2018 to 31 December 2020 for each producer or importer which has lawfully placed on the market hydrofluorocarbons from 1 January 2015 UE of 24 October 2017.

Moreover, in October 2016 the Kigali amendment to the Montreal Protocol (on Substances that Deplete the Ozone Layer) was signed in Rwanda. In July 2017, the EU formally ratified the Kigali Amendment to the Montreal Protocol, which aims to gradually reduce global production and consumption of hydrofluorocarbons (HFCs). Implementation of the agreement is expected to prevent up to 80 billion tonnes CO2 equivalent of emissions by 2050, which will make a significant contribution to the Paris Agreement. The EU member states, like other developed countries, are required to start the first reductions in 2019.
During the reporting year, the EU focused on improving the environmental management principles and rule. In December, the Commission published the decision, amending the user's guide setting out the steps needed to participate in EMAS (decision 2017/2285). The guidelines offer an additional information and guidance about the steps needed to participate in EMAS, which represents the voluntary participation by organizations in a Community eco-management, and audit scheme. In November, Commission Guidelines on Environmental Impact Assessment (EIA) were released (they include three parts: Guidance Document on Screening, Guidance Document on Scoping and Guidance Document on the preparation of the EIA Report). The Commission has updated and revised the 2001 EIA Guidance Documents to reflect both the legislative changes brought by 2014/52/EU and the current state of good practice. In February 2018, the working group of experts has started the revision of the ISO 14067 standard that specifies principles, requirements and guidelines for the quantification and communication of the carbon footprint of a product (CFP), based on International Standards on life cycle assessment.
In 2015 the European Commission adopted the Circular Economy Package, which includes revised legislative proposals on waste to stimulate Europe's transition towards a circular economy which emphasizes the need to move towards a lifecycle-driven 'circular' economy, with a cascading use of resources and residual waste that is close to zero. As part of a shift in EU policy towards a circular economy, the European Commission made four legislative proposals introducing new waste-management targets regarding reuse, recycling and landfilling. The proposals also strengthen provisions on waste prevention and extended producer responsibility, and streamline definitions, reporting obligations and calculation methods for targets. In 2017, the consensus on the Circular Economy has grown significantly in EU. In December 2017, the negotiators from the European Parliament and EU member states reached an agreement and the circular economy package should be approved in the second quarter of 2018, by both the European parliament and Member States. In January 2018, the first Europe-wide strategy on plastics was adopted. By 2030, all plastics packaging should be recyclable. The strategy also highlights the need for specific measures, possibly a legislative instrument, to reduce the impact of single-use plastics, particularly in the seas and oceans. The O&G sector will have to put a significant effort to follow the "circular philosophy" by investing in innovative technological solutions, optimization of the water use, energy efficiency and the green procurement.
European Union Health and Safety Laws Framework
Legislative Decree No. 81/2008 concerned the protection of health and safety in the workplace and was designed to regulate the work environments, equipment and individual protection devices, physical agents (noise, mechanical vibrations, electromagnetic fields, optical radiations, etc.), dangerous substances (chemical agents, carcinogenic substances, etc.), biological agents and explosive atmosphere, the system of signs, video terminals. Eni worked on the implementation of the general framework regulations on health and safety concerning prevention and protection of workers at national and European level to be applied to all kinds of workers and employees.
On June 1, 2007, the REACH Regulation of the European Union (EC No. 1907/2006 of December 18, 2006) entered into force. REACH stands for Registration, Evaluation, Authorization and Restriction of Chemicals and was adopted to improve the protection of human health, safety and the environment from the risks that can be posed and caused by chemicals, while enhancing the competitiveness of the EU chemical industry. It also promotes alternative methods for the assessment of hazardous substances in order to reduce the number of tests on animals. REACH places the burden of proof on companies. To comply with the regulation, companies must identify and manage the risks linked to the substances they manufacture and market in the EU. They have to demonstrate to the European Chemicals Agency (ECHA) how the substance can be safely used and communicate risk management measures to users. If the risks cannot be managed, Authorities can restrict the use of substances in different ways. Over time, hazardous substances should be substituted with less dangerous ones. The deadline of the REACH registration

TABLE OF CONTENTS

depends on the tonnage band of a substance and the classification of a substance; next and last deadline is 2018. Eni recognizes the importance of the Regulation EC No. 1907/2006 (REACH), the general principles of which are already an intrinsic part of the Company's commitment to sustainability and are an integral part of the culture and history of the Company. The compliance with the REACH requirements and the involvement of all the interested parties in the Company are coordinated and supervised by the HSEQ function. In particular, Eni is involved in the registration of substances to ECHA which regards a complex series of information about the characteristics of such substances and their uses and in another fundamental aspect that concerns the exchange of information between producers and importers, as well as the users of chemical substances ("downstream users").

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

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

On June 12, 2013, the Directive No. 2013/30/EU was issued with the aim of replacing the existing National Legislations and uniform the legislative approach at European level. The main elements of the EU Directive are the following:

- The Directive introduces licensing rules for the effective prevention of and response to a major accident. The licensing authority in Member States will have to make sure that only operators with proven technical and financial capacities are allowed to explore and produce oil&gas in EU waters. Public participation is expected before exploratory drilling starts in previously un-drilled areas.

- Independent national competent authorities, responsible for the safety of installations, are in charge of verifying the provisions for safety, environmental protection, and emergency preparedness of rigs and platforms and the operations conducted on them. Enforcement actions and penalties apply in case of non-compliance with the minimum set standards.

- Obligatory emergency planning calls for companies to prepare reports on major hazards, containing an individual risk assessment and risk-control measures, and an emergency response plan before exploration or production begins. These plans have to be submitted to National Authorities.

- Technical solutions presented by the operator need to be verified independently prior to and periodically after the installation is taken into operation.

- Companies are required publish on their websites information about standards of performance of the industry and the activities of the national competent authorities, as well as reports of offshore incidents.

- Companies are required prepare emergency response plans based on their rig or platform risk assessments and keep resources at hand to be able to put them into operation when necessary. These plans are periodically tested by the industry and National Authorities.

- Oil and gas companies are fully liable for environmental damage caused to the protected marine species and natural habitats. For damage to waters, the geographical zone is extended to cover all EU waters including the exclusive economic zone (about 370 km from the coast) and the continental shelf, where the coastal Member States exercise jurisdiction. For water damage, the present EU legal framework for environmental liability is restricted to territorial waters (about 22 km offshore).

- Operators working in the EU are required to demonstrate they apply the same accident-prevention policies overseas as they apply in their EU operations.

TABLE OF CONTENTS

We believe that Eni operations are currently in compliance with all those regulations in each European country where they have been enacted.

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

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

Worldwide Eni approach was to join international consortiums for main equipment and to develop in-house technologies to improve the intervention capability. Eni Emergency Response Kit consists of:

- Outsourced equipment contracted by Eni Head Quarter;
- Access Agreement to Subsea Capping Equipment consortium;
- Access Agreement to Global Dispersant Stockpile consortium;
- Eni Head Quarter proprietary equipment;
- Rapid Cube;
- Killing System.

As regards major accidents, the Seveso III (Directive No. 2012/18/EU) was adopted on July 4, 2012 and entered into force on August 13, 2012. Italy has transposed it into national legislation through the Legislative Decree No. 105/2015 (June 26, 2015).

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

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

Eni has carried out specific activities aimed at guaranteeing the compliance of its own industrial sites.

HSE activity for the year 2017

Eni is committed to continuously improving its model for managing health, safety and environment issues across all its businesses in order to minimize risks associated with its own industrial activities, ensure reliability of its industrial operations and comply with all applicable rules and regulations.
In 2017, Eni's business units continued to obtain certifications of their management systems, industrial installations and operating units according to the most stringent international standards. The total number of certifications achieved was 305, of which:

- 98 certifications according to the ISO 14001 standard;
- 11 registrations according to the EMAS regulation (EMAS is the Environmental Management and Audit Scheme recognized by the European Union);
- 21 certifications according to the ISO 50001 standard (certification for an energy management system);
- 101 according to the OHSAS 18001 standard (Occupational Health and Safety management Systems – requirements);
- 38 according to the ISO 9001 standard (certification of the quality management system).

In 2017 the percentage of Eni industrial installations and operating units with a significant HSE risk covered by certification is 97% for the OHSAS 18001 and ISO 14001 standards.

TABLE OF CONTENTS

In 2017, total HSE expenses (including cross-cutting issues such as HSE management systems implementation and certification, etc.) amounted to €1,101 million, in line with 2016.

Environment. In 2017, Eni incurred total expenditures of €756.16 million for the protection of the environment (with an increase of 28.5% with respect to 2016). Environmental expenditures are mainly related to remediation and reclamation activities (€260.7 million), waste management (€225.8 million), water management (€99.7 million), air protection (€55.1 million) and spill prevention (€53.4 million).

Safety. Eni is committed to safeguarding the safety of its employees, contractors and all people living in the areas where its activities are conducted and its assets located. In 2017, the new legislation didn't impact significantly procedures already in place for safety in the workplace.

The dissemination of safety culture is a primary target for Eni. In 2017, in order to increase safety's culture in the workforce, awareness-raising initiatives continued. Road Shows and Safety Day were organized with the aim of sharing performance, target, new projects and safety vision between Eni's top management and employees and contractors.

In order to keep developing new awareness raising actions regarding safety at work, in 2017 two initiatives, launched in 2016, continued:

- "Inside Lesson Learned Project" to share lessons learned using video clips made by internal resources and inspired by real events occurred in the company;

- "Eni in Safety 2" to increase safety culture with workshops finalized to discuss safe behaviors, responsibility and leadership in safety involving employees and contractors.

In 2013, Eni launched an initiative aimed at issuing work permits in electronic form for standardizing and improving the related risk assessment process. The initiative is progressively involving all the operating sites.

In 2015, Eni developed the Company Process Safety Management System for increasing the safety of its operations through still higher technical and management standards. Starting from 2016 and in following years these standards are applied progressively in all operating activities.

Results of efforts to achieve a better safety in all activities brought an improvement of Eni workforce total recordable injury rate (0.33), decreased by 6.8% compared to 2016.

Regarding emergency preparedness, Eni has joined the Oil Spill Response-Joint Industry Project (OSR-JIP I & II) which was launched in December 2011 by International Association of Oil&Gas Producers (IOGP) and International Petroleum Industry Environmental Conservation Association (IPIECA) and concluded in 2016. The JIP executed the outstanding recommendations from the report produced by the Global Industry Response Group (GIRG) set-up after the Macondo accident.

The JIP aimed at:

- providing a forum for industry to share knowledge on the science, tools and techniques;

- representing the industry on approaches for oil spill preparedness and response, working closely with other associations on communications with both national and global regulatory groups;

- engaging pro-actively in broader outreach and communication.

The OSR-JIP carried out specific projects dealing with exercise planning, in situ burning, dispersants advocacy-subsea, efficacy-post spill monitoring, upstream risk assessment and response capability, etc., publishing 11 Research Reports, 9 Technical Reports and 24 Good Practice Guidance during 2017 the translation into various languages (Italian for example) was completed..

Costs incurred in 2017 to support the safety levels of operations and to comply with applicable rules and regulations were €249.8 million.

Health. Eni's activities for protecting health aim to continuously improve the psychophysical wellbeing of people in the workplace. Eni believes that it achieved a good performance in this area thanks to:

- plant and facility efficiency and reliability;

TABLE OF CONTENTS

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

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

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

In 2017 Eni had a big expansion towards the green economy with the transformation of some traditional refineries into green ones for the development of green products; this saw a big involvement in evaluation and registration of green products.

Path to decarbonization

Eni intends to play a leading role in the energy transition process, supporting the objectives of the Paris Agreement. Eni has been committed for a long time to promoting full and effective disclosure on climate change and is the only company in the Oil & Gas industry to take part in the Task Force on Climate-related Financial Disclosures (TCFD) of the Financial Stability Board. In June 2017 the latter published its voluntary recommendations to encourage effective disclosure of the financial implications of climate change; Eni is committed to a gradual implementation of these recommendations.

Below is a Dashboard which shows the reports/documents containing climate information based on the four areas covered by the TCFD recommendations and the relevant level of detail.

TABLE OF CONTENTS

Recommendation	ANNUAL REPORT ON FORM 20-F (Management Discussion)	SUSTAINABILITY REPORT [Addendum Eni For]
GOVERNANCE		
Disclose the organization's governance around climate-related risks and opportunities.	√ Key elements	√
STRATEGY		
Disclose the actual and potential impacts of climate-related risks and opportunities on the organization's businesses, strategy, and financial planning where such information is material.	√ Key elements	√
RISK MANAGEMENT		
Disclose how the organization identifies, assesses, and manages climate-related risks.	√ Key elements	√
METRICS & TARGETS		
Disclose the metrics and targets used to assess and manage relevant climate-related risks and opportunities where such information is material.	√ Key elements	√

Governance

Eni's decarbonization strategy is part of a structured system of Corporate Governance; within this, the Board of Directors (BOD) and the Chief Executive Officer (CEO) play a central role in managing the main aspects linked to climate change.

The BOD examines and approves, based on the CEO's proposal, the strategic plan which defines strategies and includes objectives also on climate change and energy transition; every six months it is also informed on the progress of the main projects, where the operating, economic and financial key performance indicators (KPIs) are reported.

Since 2014, the BOD has been supported in conducting its duties by the Sustainability and Scenarios Committee (CSS), which examines, on a periodic basis, the integration between strategy, future scenarios and the medium to long-term sustainability of the business. During 2017, at all twelve CSS meetings, detailed discussions were held on aspects related to decarbonization strategy, energy scenarios, renewable energy, R&D to support energy transition and climate partnerships.

Since the second half of 2017, the BOD and the CEO are also supported by an Advisory Board, composed of international experts, focused on topics related to the decarbonization process.

The CEO also chairs the Steering Committee of the Climate Change Program, a cross-functional working group composed of members of Eni's top management with the aim of developing and monitoring appropriate medium/long-term decarbonization strategies. The CEO's short-term monetary plan has a weight of 12.5% to the objective of reducing the intensity of upstream GHG emissions in line with the long term target; the same objective has been given to all the managers who have a strategic role on this matter.

As evidence of the attention paid to climate change and the clear decarbonization strategy embarked upon, in 2015 a business unit dedicated to the development of renewable energy (Energy Solutions Department) was established, directly reporting to the CEO.

Among the many international climate initiatives that Eni participates in, Eni's CEO has a leading role in the Oil and Gas Climate Initiative (OGCI); in 2014 Eni was one of the five founding companies of the initiative which now counts ten companies, representing more than 25% of the global hydrocarbon production. The OGCI is currently engaged in the joint investment of $1 billion over 10 years in the development of technologies to reduce GHG emissions along energy value chain.

Eni has also been actively involved, since the start of its work, in the Task Force on Climate Related Financial Disclosure (TCFD), set up by the Financial Stability Board with the aim of defining recommendations for company's climate change disclosure, published during 2017.

In 2017, based on its strategies and actions, Eni was confirmed as a climate change leader by CDP (ex Carbon Disclosure Project), the main independent rating agency that assesses international companies with a high market capitalization.

TABLE OF CONTENTS

Risk Management

Eni has developed and adopted an Integrated Risk Management (IRM) Model to ensure that management takes risk-informed decisions, taking fully into consideration current and potential future risks, including medium and long-term ones, as part of an organic and comprehensive vision. The model also aims to raise awareness, at all company levels, that appropriate risk assessment and management has an important effect on the achievement of company objectives and values.

The process is implemented using a "top-down risk based" approach, starting from the contribution to the definition of Eni's Strategic Plan, by means of analyses that support the understanding and evaluation of the likelihood of underlying risk (e.g. definition of specific de-risking objectives) and continue with the support for its implementation through periodic risk assessment & treatment cycles and monitoring. Risk prioritization is carried out on the basis of multi-dimensional matrices which measure the level of risk by combining clusters of probability of occurrence and impact.

The risk of Climate Change is identified as one of Eni's top strategic risks and is analysed, assessed and monitored by the CEO as part of the IRM process. The analysis is carried out using an integrated and cross-cutting approach which involves specialist departments and business areas and considers both aspects correlated with energy transition (market scenario, regulatory and technological developments, reputation issues) and physical aspects (extreme/chronic weather and climate phenomena), as described in the Strategy section.

Strategy

Main risks and opportunities

The climate change risk is analysed taking into account five drivers for which the main results are shown below.

Market scenario. In a low carbon scenario, as in the IEA SDS6 (WEO 2017), the role of fossil fuels remains central to the energy mix. Natural gas, that increases also in the SDS scenario, represents an opportunity for strategic repositioning for oil&gas companies, due to its lower carbon intensity and the possibility of integration with renewable sources in electricity production. Although the IEA SDS scenario foresees the oil demand reaching a peak in around 2020 and going down to 75 Mb/d in 2040, the need for significant investments in the upstream sector to compensate for the drop in production from existing fields. There is residual uncertainty linked to the effect that regulatory developments and breakthrough technologies could have on the scenario, with a consequent impact on the company business model.

Regulatory developments. The adoption of policies (e.g. reduction of emissions, also from deforestation; carbon pricing; development of renewable sources; energy efficiency; diversification of electricity production; advanced biofuels; electric vehicles; etc.) designed to support energy transition to low carbon sources could have significant impacts on the business. The differentiated approach by country could provide an advantage for the development of new business opportunities.

Technological developments. Technologies to capture and reduce GHG emissions as well as leaks of natural gas along the oil&gas value chain will be fundamental for affirming the dominant role of natural gas in the global energy mix. On the other hand, technological development in the field of renewable energy production and storage and in the efficiency of electric vehicles could have impacts on the demand for hydrocarbons and therefore on the business. The capacity to rapidly intercept and integrate technological breakthroughs in the business will play a key role in business competitiveness.

Reputation. The increasing attention being given to climate change has a negative impact on the reputation of the entire oil&gas industry, seen as one of the main parties responsible for GHG emissions, with effects on the management of relations with the key stakeholders. The ability to develop and implement strategies to adapt the business model to a low-carbon scenario, as well as the capacity to communicate these in a transparent manner provides an opportunity to improve stakeholder perceptions.

Physical risks. The intensification of extreme/chronic weather and climate phenomena could result in an increase in costs (including insurance) for adaptation measures to protect assets and people. The IPCC (Intergovernmental Panel on Climate Change) scenarios predict that these physical effects will manifest themselves mainly over the medium to long term. The exposure to risk is mitigated by the design requirements adopted (defined to resist extreme environmental conditions) and the insurance covers taken out.

6
International Energy Agency- Sustainable Development Scenario from the World Energy Outlook 2017.

89

TABLE OF CONTENTS

Strategy and objectives

In relation to the risks and opportunities described above, Eni has defined a path to decarbonization and pursues a clear and well-defined climate strategy, integrated with its business model, which is based on the following drivers:

- reduction in direct GHG emissions; from 2014 to 2017 the actions taken have enabled the GHG emission intensity index of the upstream sector to be reduced by 15%; the goal is to reduce this rate by 43% by 2025 compared to 2014 through projects to eliminate process flaring, reduce fugitive emissions of methane (for the upstream segment by 80% in 2025 compared to 2014) and energy efficiency projects; in total the investments in support of these targets add up to an expenditure of about €0.6 billion in 2018-21, at 100% and with reference only to upstream operated activities;

- “low carbon” oil&gas portfolio characterized by conventional projects developed in stages and with low CO2 intensity. The new upstream projects being executed, which represent about 65% of the total development investments in the sector in the 2018-21 four-year period, have break-even points below 30 $/bl, and are therefore resilient even in low-cabon scenarios. In general, Eni’s portfolio has hydrocarbon resources with a high natural gas percentage, a bridge towards a reduced emissions future. The mid-downstream segment is less exposed to climate change risk, as the net book value of traditional refineries and petrochemical plants is negligible compared to the total assets of the group, while the green component of this business is being developed;

- green business development through i) a growing commitment to renewable energy (approximately 1,000 MW installed power in 2021); ii) development of the second phase of the Venice biorefinery (with a maximum capacity of 560 ktonnes/y from 2021) and the completion of the Gela biorefinery (with maximum capacity of 720 ktonnes/ y) by 2018; iii) strengthening of Green Chemistry, with production of bio-intermediates from vegetable oil at Porto Torres (capacity of 70 ktonnes/year), studies, pilot projects and partnerships with other operators. In the 2018 – 2021 four-year period, total investments are expected at more than €1.8 billion, including the scientific and technological development (R&D) activities related to the path to decarbonization;

- commitment to scientific and technological research (R&D), essential for achieving maximum efficiency in the decarbonisation process.

The composition of the portfolio and Eni’s strategy minimize the risk of “stranded assets” in the upstream sector; in this regard, the management has subjected to a sensitivity analysis the book value of all CGUs (Cash Generating Units) in the upstream sector, adopting the IEA SDS scenario; this stress test highlighted the substantial retention of the asset book values, with a reduction of about 4% of the fair value.

Metrics and comments

Below are described the main performances, showing the results achieved by Eni to date in relation to the decarbonization strategy.

In 2017 all the production emission indexes recorded an improvement compared to 2016. In particular, in the E&P sector the GHG intensity index calculated per unit of gross hydrocarbon unit produced – on operatorship basis – fell by 2.7% compared to the previous year, amounting to 0.162 tonCO2eq/toe; the overall variation in the index compared to 2014 is -15%, in line with the target of 43% reduction by 2025. Also in the other sectors, the GHG emission intensity has decreased, in particular Enipower’s emission index has decreased by 0.8% and the refineries’ by 7%.

Since 2010, Eni’s direct emissions on operatorship basis have been reduced by 27%, although last year reported an increase of 2.5% compared to 2016 due to the rise in combustion and process emissions as a result of increased production in the E&P segment (in particular activities in Libya and start-ups in Ghana, Angola and Indonesia) and in G&P (where both electricity production and volumes of natural gas transported have increased). In line with its decarbonisation strategy, during 2017 Eni has purchased and cancelled in its favour 680,193 forestry credits in the international market, thus offsetting about half of the increase in direct emissions compared to 2016.

Compared to Eni's main GHG emissions sources, since 2014 the volume of hydrocarbons sent to process flaring decreased by 7%. Emissions from flaring increased in the last year, despite the fact that Eni invested €29 million in flaring down projects in 2017 (in particular in Nigeria and Libya). This was due

90

TABLE OF CONTENTS

both to new start-ups and the restart of the Abu Attifel field in Libya, which was shut down in 2016 due to the difficult situation in the country. Fugitive emissions of methane (equal to about 80% of total methane emissions) have decreased in the E&P and G&P segments, both due to periodic maintenance activities (the so-called LDAR – Leak Detection and Repair campaigns) carried out on sites already subject to monitoring in previous years and the extension of the survey to new sites, with an improvement in the accuracy of emissions estimates based on actual plant configuration. The energy efficiency initiatives carried out in 2017 allow, in full operation, energy savings for around 300 ktoe/year, amounting to a reduction in emissions of approx 0.8 million tonnes of CO2eq. In 2017, Eni invested €9 million in energy efficiency projects.

In 2017, Eni's investment in scientific research and technological development amounted to €185 million, of which €72 million relating to the Path to Decarbonization. This investment refers to: energy transition, biorefining, green chemistry, renewable sources, emissions' reduction and energy efficiency.

In 2017, production of biofuels reached 206 thousand tonnes, an all-time record, with an increase of more than 14% over the previous year.

		2017		2016		2015	
Key sustainability performance indicators		Operated companies	Fully consolidated entities	Operated companies	Fully consolidated entities	Operated companies	Fully cons entiti
Direct GHG emissions (Scope 1)	(mln tonnes CO2eq)	42.52	27.04	41.46	26.48	42.32	27.1
of which: CO2eq from combustion and process		32.65	22.61	31.99	22.64	32.22	23.0
of which: CO2eq from flaring		6.83	3.37	5.4	2.49	5.51	2.47
of which: CO2eq from non-combusted methane and fugitive emissions		1.46	0.84	2.4	1.16	2.79	1.34
of which: CO2eq from venting		1.58	0.23	1.67	0.19	1.8	0.3
GHG emisions/100% operated hydrocarbon gross production (E&P)	(tonnes CO2eq/toe)	0.162	0.176	0.166	0.163	0.177	0.19
GHG emissions/kWheq (EniPower)	(gCO2eq/kWheq)	395	398	398	402	409	413
GHG emissions/products (crude oil and semifinished) processed in refineries	(tonCO2eq/kt)	258	258	278	278	253	253
Widespread emissions and methane fugitive emissions (upstream)	(tonCH4)	38,819	19,413	72,644	30,331	91,416	36,76
Volumes of hydrocarban sent to	(MSm3)	2,283	1,262	1,950	1,112	1,989	1,15

flaring							
of which: sent to process flaring		1,556	594	1,530	767	1,564	774
Net consumption of primary resources	(Mtoe)	13.15	9.06	12.52	8.75	12.76	9.02
Primary energy purchased from other companies	(Mtoe)	0.38	0.33	0.44	0.38	0.38	0.32
Electricity produced by solar panels (EniPower)	MWh	14,720	14,720	13,527	13,527	13,750	13,75
Energy comsuption of producing activities/Hydrocarbon production (100% E&P operated)	(GJ/toe)	1.487	na	1.711	na	1.595	na
Net consumption of primary resources/electricity produced (EniPower)	(toe/MWheq)	0.162	0.163	0.163	0.164	0.168	0.169
Energy Intensity Index (refineries)	(%)	109.2	109.2	101.7	101.7	100.3	100.3
R&D expenditures	(€ million)	185		161		176	
of which: new energy		58		51		—	
First patent filing applications	(number)	27		40		33	
of which filed on renewable sources		11		12		16	
Production of biofuels	(ktonnes)	206		181		179	
Biorefineries capacity	(ktonnes/year)	360		360		360	

91

TABLE OF CONTENTS
Regulation of Eni's businesses
Overview
The matters regarding the effects of recent or proposed changes in Italian legislation and regulations or EU directives discussed below and elsewhere herein are forward-looking statements and involve risks and uncertainties that could cause the actual results to differ materially from those in such forward-looking statements. Such risks and uncertainties include the precise manner of the interpretation or implementation of such legal and regulatory changes or proposals, which may be affected by political and other developments.
Regulation of exploration and production activities
Eni's exploration and production activities are conducted in many countries and are therefore subject to a broad range of legislation and regulations. These cover virtually all aspects of exploration and production activities, including matters such as license acquisition, production rates, royalties, pricing, environmental protection, export, taxes and foreign exchange. The terms and conditions of the leases, licenses and contracts under which these oil&gas interests are held vary from country to country. These leases, licenses and contracts are generally granted by or entered into with a government entity or state company and are sometimes entered into with private property owners. These arrangements usually take the form of licenses or production sharing agreements. See "Regulation of the Italian hydrocarbons industry" and "Environmental matters" for a description of the specific aspects of the Italian regulation and of environmental regulation concerning Eni's exploration and production activities. Licenses (or concessions) give the holder the right to explore for and exploit a commercial discovery. Under a license, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the license holder is entitled to all production minus any royalties that are payable in-kind. A license holder is generally required to pay production taxes or royalties, which may be in cash or in-kind. Both exploration and production licenses are generally for a specified period of time (except for production licenses in the United States which remain in effect until production ceases). The term of Eni's licenses and the extent to which these licenses may be renewed vary by area. In production sharing agreements, entitlements to production volumes are defined on the basis of contractual agreements drawn up with state oil companies holding the concessions. Such contractual agreements regulate the recovery of costs incurred for the exploration, development and operating activities (Cost Oil) and give entitlement to a portion of the production volumes exceeding volumes destined to cover costs incurred (Profit Oil). A similar scheme to PSA applies to Service and "buy-back" contracts. In general, Eni is required to pay income tax on income generated from production activities (whether under a license or PSA). The taxes imposed upon oil&gas production profits and activities may be substantially higher than those imposed on other businesses.
Regulation of the Italian hydrocarbons industry
The matters regarding the effects of recent or proposed changes in Italian legislation and regulations or EU directives discussed below and elsewhere herein are forward-looking statements and involve risks and uncertainties that could cause the actual results to differ materially from those in such forward-looking statements. Such risks and uncertainties include the precise manner of the interpretation or implementation of such legal and regulatory changes or proposals, which may be affected by political and other developments.
Exploration & Production
The Italian hydrocarbons industry is regulated by a combination of constitutional provisions, statutes, governmental decrees and other regulations that have been enacted and modified from time to time, including legislation enacted to implement EU requirements (collectively, the "Hydrocarbons Laws").
Exploration permits and production concessions. Pursuant to the Hydrocarbons Laws, all hydrocarbons existing in their natural condition in strata in Italy or beneath its territorial waters (including its continental shelf) are the property of the State. Exploration activities require an exploration permit, while production activities require an exploiting concession, in each case granted by the Minister of Economic Development. The initial duration of an exploration permit is six years, with the possibility of obtaining two three-year extensions and an additional one-year extension to complete activities underway. Upon each of the three-year extensions, 25% of the area under exploration must be relinquished to the State (only for initial acreages larger than 300 square kilometers). The initial duration of a production concession is 20 years, with the possibility of obtaining a ten-year extension and additional five-year extensions until the field depletes.

TABLE OF CONTENTS

Royalties. The Hydrocarbons Laws require the payment of royalties for hydrocarbon production. As per Legislative Decree No. 625 of November 25, 1996, subsequent modifications and integrations and Law Decree No. 83 of June 22, 2012, royalties are equal to 10% for gas and oil productions onshore, to 10% for gas and 7% for oil offshore, with fixed amount of exemption. Only in the Autonomous Region of Sicily, following the Regional Law No. 9 of May 15, 2013, royalties onshore for oil and gas are equal to 20,06%, with no exemptions).

Gas & Power

Natural gas market in Italy

New liberalization measures in Italy

Law Decree No. 1 enacted by the Italian Government on January 24, 2012, the so-called Liberalization Decree, was converted to Law No. 20 on March 24, 2012. This law aimed at:

- enhancing competitiveness in gas tariffs to residential customers and in the distribution of refined products. The ARERA, in charge with setting pricing mechanisms for supplies to final users, starting from the second quarter of 2012 updated the indexation mechanism by gradually increasing the weight of spot prices in the indexation of the supply costs of gas that previously used to be oil-linked; and

- reforming the storage system introducing market-based mechanisms for the allocation of storage capacity, moving away from the traditional "pro-rata"/tariff system, and with the aim to reduce the cost of natural gas for industrial customers. In particular:

  - for an amount determined by the Ministry itself, storage capacity started to be primarily reserved for the offer to industrial sector of an integrated service (international transport of liquefied natural gas, regasification and storage), thus allowing industrial clients to supply natural gas directly from abroad in the form of liquefied natural gas; and

  - the remaining amount of storage capacity started to be assigned via auction procedures devoted to the modulation needs.

Based on the principles described above, the Minister of Economic Development and the ARERA establish every year the detailed criteria for the allocation of gas storage capacities.

In 2017, 1,5 BCM of integrated storage and regasification capacity was offered to the industrial sector.

Such integrated service is no longer offered since 2018, due to a new market-based mechanism for allocating regasification capacities in Italy introduced by the Italian regulator.

With three operating LNG regasification terminals, Italy has a lot of regasification capacity, about half of which was not used in 2017. The Adriatic LNG terminal has a capacity of 8 billion cubic metres (BCM)/ year, while capacity at OLT and Panigaglia is 3.75 BCM/y and 3.5 BCM/y, respectively. The low interest in accessing to and using regasification capacity on a spot or monthly basis is mainly due to the high level of regasification tariffs in Italy compared to the rest of Europe. The new market-based system for allocating regasification capacity in Italy is working on principles similar to the ones already set for the mechanisms for allocating storage capacity and it is therefore based on auctions that will express the market-value of the regasification capacity.

Such new mechanism is likely to attract more LNG deliveries to the country in the future.

Management believes that these new regulation will increase competition in the wholesale natural gas market in Italy, leading to possible margin pressures.

Negotiation platform for gas trading and gas balancing market and other measures to increase gas market liquidity

In compliance with the provisions of Law No. 99 of July 23, 2009, on March 18, 2010, the Ministry of Economic Development published a decree that implements a trading platform for natural gas starting from May 10, 2010, aimed at increasing competition and flexibility on wholesale markets. Management and organization of this platform (MGAS) are entrusted to an independent operator, the Gestore dei Mercati Energetici (GME), an Italian agency. In the

MGAS, parties authorized to carry out transactions at the "Punto di Scambio Virtuale" (PSV – Virtual Trading Point) may make forward and spot purchases and sales of volumes of natural gas. In the MGAS, GME plays the role of central counterparty to the transactions concluded by Market Participants.

TABLE OF CONTENTS

In October 2016 the new gas balancing regime – an evolution of the one already in place – has entered into force in the Italian system in compliance with the EU regulatory framework. This system is based on the principle that network users have to balance their daily position, also in accordance with the timely information provided by Snam Rete Gas about the daily gas consumption. The new gas balancing regime provides for:

- the possibility for shippers to modify intra-day the gas nominations;
- the possibility for shippers to trade on the market with other shippers and/or with the TSO itself (that can access the market under some constraints, in order to address overall system balancing needs that may arise on top of shippers' activities)
- the incentive for shippers to balance their position via penalizing imbalance prices.

To foster market liquidity, starting from April 2017 all of the above-mentioned gas trading activities were concentrated on the MGAS, managed by GME, as one single platform.

In addition, since February 2018 voluntary market making activity has been introduced in the spot section of the gas exchange MGAS. Such activity is based on the service provided by some Liquidity Providers, in order to boost liquidity and trading activity on the same exchange, initially for the day-ahead market but with possible future extension to the within-day section and to the forward section of the MGAS.

Management believes that these measures have increased, and will further increase, the level of liquidity in the Italian spot market of gas.

Natural gas prices in the retail sector

Following the liberalization of the natural gas sector introduced in the year 2000 by Decree No. 164, prices of natural gas in the wholesale market which includes industrial and power generation customers are freely negotiated. However, the ARERA holds a power of surveillance on this matter (see below) under Law No. 481/1995 (establishing the ARERA) and Legislative Decree No. 164/2000. Furthermore, the ARERA is still entrusted (as per the Presidential Decree dated October 31, 2002) with the power of regulating natural gas prices to residential customers, also with a view of containing inflationary pressure deriving from increasing energy costs. Consistently with those provisions, companies which sell natural gas to residential customers are currently required to offer to those customers the regulated tariffs set by ARERA beside their own price proposals.

In 2013, a new tariff regime was enacted for Italian residential clients who are entitled to be safeguarded in accordance with current regulations. Clients who are eligible for the tariff mechanism set by the ARERA are residential clients (including residential buildings consuming less than 200,000 CM/y). With Resolution No. 196 effective from October 1, 2013, the ARERA reformulated the pricing mechanism of gas supplies to those customers by providing a full indexation of the raw material cost component of the tariff to spot prices versus the previous regime that provided a mix between an oil-based indexation and spot prices.

The new tariff regime intended to partially offset the negative impact born by wholesalers by introducing a pricing component intended to cover the risks and costs of the supplies to wholesalers. Furthermore, it was provided a stability mechanism whereby a wholesaler part of a long-term, take-or-pay gas supply contract could opt to be reimbursed for the possible negative difference between the oil-linked costs of gas supplies and spot prices in the two thermal years following the implementation of the new regime; conversely, in case spot prices fall below the oil-linked cost of gas supplies in the following two thermal years, the same wholesaler had to refund customers of the difference. Based on this compensation mechanism, which expired in September 2016, Eni totaled about €160 million of reimbursement over three thermal years, starting in October 2013 and ending in September 2016.

This tariff regime also reduced the tariff components intended to cover storage and transportation costs. Finally, it also increased the specific pricing component intended to remunerate certain marketing costs incurred by retail operators, including administrative and retention costs, losses incurred due to customer default and a return on capital employed.

TABLE OF CONTENTS

Furthermore, the new tariff mechanism indexed to TTF (Title Transfer Facility) for residential clients will be applicable until the end of thermal year 2017 – 2018.

However, the Law 124/17 provided the complete abrogation of the tariffs for gas and power effective from July 1, 2019. The Law 124/17 will be implemented through a Ministerial Decree that is still under discussion. Referring to the electricity and gas markets, residential customers would choose prices on the free market, potentially, lower than the regulated ones.

Similarly other Regulatory Authorities in European countries where Eni is present have issued regulations referring to hub component in the pricing formulas related to retail clients, as well as measures to boost liquidity and competitiveness in the gas market.

Refining and marketing of petroleum products

Refining. The regulations introduced with Law No. 9/1991 and No. 239/2004 (Article 1, paragraphs 56, 57 and 58) significantly changed the norms introduced in the 1930's that required that any refining activity be handled under a concession from the State. Today an authorization is required to set up new processing and storage plants and for any change in the capacity of mineral processing plants, while all other changes that do not affect capacity can be freely implemented. Another simplification measure was introduced by Law Decree No. 5/2012 that defined mineral oil processing and storage plants as "strategic settlements" that need authorization from the State, in agreement with the relevant Region, and imposes a single process of authorization that must be closed within 180 days, subject to the authorizations requested by environmental regulations. Management expects no material delays in obtaining relevant concessions for the upgrading of the Sannazzaro and Taranto refineries as planned in the medium term.

Marketing. Following the enactment of the above-mentioned Law Decree No. 1 on January 24, 2012, certain measures are expected to be introduced in order to increase levels of competition in the retail marketing of fuels. The rules regulating relations between oil companies and managers of service stations have been changed introducing the difference between principal and non-principal of a service station. Starting from June 30, 2012, principals will be allowed to freely supply up to 50% of their requirements. In such case, the distributing company will have the option to renegotiate terms and conditions of supplies and brand name use. As for non-principals, the law allows the parties to renegotiate terms and conditions at the expiration of existing contracts and new contractual forms can be introduced in addition to the only one allowed so far, i.e. exclusive supply. The law also provides for an expansion of non-oil sales. Eni expects developments on this issue to further increase pressure on selling margins in the retail marketing of fuels and to reduce opportunities of increasing Eni's market share in Italy. Furthermore, the law 205/2017 provides some measures for preventing of tax evasion in the sale of oil products that in the past produced anticompetitive effects on the sector. The law requires the advance payment of Value Added Tax (VAT) on oil products before the extraction from deposits or the sale to consumer.

Service stations. Legislative Decree No. 32 of February 11, 1998, as amended by Legislative Decree No. 346 of September 8, 1999 and Law Decree No. 383 of October 29, 1999, as converted in Law No. 496 of December 28, 1999, significantly changed Italian regulation of service stations. Legislative Decree No. 32 replaces the system of concessions granted by the Ministry of Industry, regional and local authorities with an authorization granted by city authorities while the Legislative Decree No. 112 of March 31, 1998 still confirms the system of such concessions for the construction and operation of service stations on highways and confers the power to grant to Regions. Decree No. 32 also provides for: (i) the testing of compatibility of existing service stations with local planning and environmental regulations and with those concerning traffic safety to be performed by city authorities; (ii) the option to extend by 50% the opening hours (currently 52 hours per week) and a generally increased flexibility in scheduling opening hours; (iii) simplification of regulations concerning the sale of non-oil products and the permission to perform simple maintenance and repair operations at service stations; and (iv) the opening up of the logistics segment by permitting third-party access to unused storage capacity for petroleum products. With the same goal of renewing the Italian distribution network, Law No. 57 of March 5, 2001 provides that the Ministry of Economic Development is to prepare guidelines for the modernization of the network, and the Regions shall follow those guidelines in the preparation of regional plans. The subsequent Ministerial Decree of October 31, 2001 establishes the criteria for the closing down of incompatible stations, the approval of the plan, the renewal of the network, the opening up of new stations and the regulations of the operations of

TABLE OF CONTENTS

service stations on matters such as automation, working hours and non-oil activities. After the approval of Law No. 133/2008, Article 28 of Law Decree No. 98/2011 converted into Law No. 111/2011, contains new guidelines for improving market efficiency and service quality and increasing competition. Among other things, it requires that from July 6, 20112 all service stations must be provided with self-service equipment and that Regions will update their regulations in order to allow the sale of non-oil products in all service stations. Law Decree No. 1/2012 also allowed the installation of fully automated service stations with prepayment, but only outside city areas. Law No. 133 of August 6, 2008, by intervening in competition provisions, removes some national and regional regulations, which might limit the liberty of establishment and introduces new provisions particularly concerning the elimination of restrictions concerning distances between service stations, the obligation to undertake non-oil activities and the liberalization of opening hours.

The new regulatory framework provided by the legislative decree No 257/2016 – implementing EU Directive 2014/94/UE on alternative fuel infrastructures – could involve a significant development in the fuel market for transport sector.

In order to mitigate environmental impacts of the transport sector, the legislation sets forth minimum requirements for the construction of infrastructure for the development of alternative fuels.

The law includes measures simplifying administrative procedures for the granting of government permits related to the construction of the main logistic infrastructures for the country. The legislation established, furthermore, an adequate number of charging stations accessible to the public to be created throughout the country by 2020

Finally, Law no. 124/2017 aims to promote the structural reorganization of the fuel distribution network also in order to increase competition and efficiency. The law requires the closure of fuel stations that are incompatible with road safety regulations and environmental streamlining procedures for the decommissioning.

Management believes that these measures will favor competition in the Italian retail market and enhance the competitiveness of efficient players.

Petroleum product prices. Petroleum products' prices were completely deregulated in May 1994 and are now freely established by operators. Oil and gas companies periodically report their recommended prices to the Ministry of Economic Development; such recommendations are considered by service station operators in establishing retail prices for petroleum products.

Compulsory stocks. According to Legislative Decree of January 31, 2001, No. 22 ("Decree 22/2001") enacting Directive No. 1993/98/EC (which regulates the obligation of Member States to keep a minimum amount of stocks of crude oil and/or petroleum products) compulsory stocks, must be at least equal to the quantities required by 90 days of consumption of the Italian market (net of oil products obtained by domestically produced oil). In order to satisfy the agreement with the International Energy Agency (Law No. 883/1977), Decree No. 22/2001 increased the level of compulsory stocks to reach at least 90 days of net import, including a 10% deduction for minimum operational requirements. Decree No. 22/2001 states that compulsory stocks are determined each year by a decree of the Minister for Economic Development based on domestic consumption data of the previous year, defining also the amounts to be held by each oil company on a site-by-site basis. The Legislative Decree No. 249/2012, entered into force on February 10, 2013 to implement the Directive No. 2009/119/EC (imposing an obligation on Member States to maintain minimum stocks of crude oil and/or petroleum products), sets forth in particular: (a) that a high level of oil security of supply through a reliable mechanism to assure the physical access to oil emergency and specific stocks shall be kept; and (b) the institution of a Central Stockholding Entity under the control of the Ministry for Economic Development that should be in charge of: (i) the purchase, holding, sell and transportation of specific stocks of products; (ii) the stocktaking; (iii) the statistics on emergency, specific and commercial stocks; and, eventually (iv) the storage and transportation service of emergency and commercial stocks in favor of sellers of petroleum products not vertically integrated in the oil chain. As of December 31, 2017, Eni owned 5.4 mmtonnes of oil products inventories, of which 3.5 mmtonnes as "compulsory stocks", 1.7 mmtonnes related to operating inventories in refineries and deposits (including 0.2 mmtonnes of oil products contained in facilities and pipelines) and 0.2 mmtonnes related to specialty products. Eni's compulsory stocks were held in term of crude oil (35%), light and medium distillates (35%), refinery feedstock (22%), fuel oil (4%) and other products (4%) were located throughout the Italian territory both in refineries (85%) and in storage sites (15%).

Competition

Like all Italian companies, Eni is subject to Italian and EU competition rules. EU competition rules are set forth in Articles 101 and 102 of the Lisbon Treaty on the Functioning of the European Union
96

TABLE OF CONTENTS

entered into force on December 1, 2009 ("Article 101" and "Article 102", respectively being the result of the new denomination of former Articles 81 and 82 of the Treaty of Rome as amended by the Treaty of Amsterdam dated October 2, 1997 and entered into force on May 1, 1999) and EU Merger Control Regulation No. 139 of 2004 (EU Regulation 139). Article 101 prohibits collusion among competitors that may affect trade among Member States and that has the object or effect of restricting competition within the EU. Article 102 prohibits any abuse of a dominant position within a substantial part of the EU that may affect trade among Member States. EU Regulation 139 sets certain turnover limits for cross-border transactions, above which enforcement authority rests with the European Commission and below which enforcement is carried out by national competition authorities, such as the Antitrust Authority in the case of Italy. On May 1, 2004, a new regulation of the European Council came into force (No. 1/2003) which substitutes Regulation No. 17/1962 on the implementation of the rules on competition laid down in Articles 101 and 102 of the Treaty. In order to simplify the procedures required of undertakings in case of conducts that potentially fall within the scope of Article 101 and 102 of the Treaty, the new regulation substitutes the obligation to inform the Commission with a self-assessment by the undertakings that such conducts does not infringe the Treaty. In addition, the burden of proving an infringement of Article 101(1) or of Article 102 of the Treaty shall rest on the party or the authority alleging the infringement. The undertaking or association of undertakings claiming the benefit of Article 101(3) of the Treaty shall bear the burden of proving that the conditions of that paragraph are fulfilled. The regulation defines the functions of authorities guaranteeing competition in Member States and the powers of the Commission and of national courts. The Competition Authorities of the Member States shall have the power to apply Articles 101 and 102 of the Treaty in individual cases. For this purpose, acting on their own initiative or on a complaint, they may take the following decisions:

- requiring that an infringement be brought to an end;
- ordering interim measures;
- accepting commitments; and
- imposing fines, periodic penalty payments or any other penalty provided for in their national law.

National courts shall have the power to apply Articles 101 and 102 of the Treaty. Where the Commission, acting on a complaint or on its own initiative, finds that there is an infringement of Article 101 or of Article 102 of the Treaty, it may: (i) require the undertakings and associations of undertakings concerned to bring such infringement to an end; (ii) order interim measures; (iii) make commitments offered by undertakings to meet the concerns expressed to them by the Commission binding on the undertakings; and (iv) find that Articles 101 and 102 of the Treaty are not applicable to an agreement for reasons of Community public interest. Eni is also subject to the competition rules established by the Agreement on the European Economic Area (the "EEA Agreement"), which are analogous to the competition rules of the Lisbon Treaty (ex Treaty of Rome) and apply to competition in the European Economic Area (which consists of the EU and Norway, Iceland and Liechtenstein). These competition rules are enforced by the European Commission and the European Free Trade Area Surveillance Authority. In addition, Eni's activities are subject to Law No. 287 of October 10, 1990 (the "Italian Antitrust Law"). In accordance with the EU competition rules, the Italian Antitrust Law prohibits collusion among competitors that restricts competition within Italy and prohibits any abuse of a dominant position within the Italian market or a significant part thereof. However, the Italian Antitrust Authority may exempt for a limited period agreements among companies that otherwise would be prohibited by the Italian Antitrust Law if such agreements have the effect of improving market conditions and ultimately result in a benefit for consumers.

Property, plant and equipment

Eni has freehold and leasehold interests in real estate in numerous countries throughout the world. Management believes that certain individual petroleum properties are of major significance to Eni as a whole. Management regards an individual petroleum property as material to the Group in case it contains 10% or more of the Company' worldwide proved oil&gas reserves and management is committed to invest material amounts of expenditures in developing it in the future. See "Exploration & Production" above for a description of Eni's both material and other properties and reserves and sources of crude oil and natural gas.

TABLE OF CONTENTS

Organizational structure

Eni SpA is the parent company of the Eni Group. As of December 31, 2017, there were 215 subsidiaries and 104 associates, joint ventures and joint operations that were accounted for under the equity or cost method or in accordance to Eni's share of revenues, costs and assets of the joint operations calculated based on Eni's working interest. Information on Eni's investments as of December 31, 2017 is provided in Note 48 to the Consolidated Financial Statements.

Item 4A. UNRESOLVED STAFF COMMENTS

None.

TABLE OF CONTENTS

Item 5. OPERATING AND FINANCIAL REVIEW AND PROSPECTS

This section is the Company's analysis of its financial performance and of significant trends that may affect its future performance. It should be read in conjunction with the Key Information presented in Item 3 and the Consolidated Financial Statements and related Notes thereto included in Item 18. The Consolidated Financial Statements are prepared in accordance with International Financial Reporting Standards as issued by the IASB.

This section contains forward-looking statements, which are subject to risks and uncertainties. For a list of important factors that could cause actual results to differ materially from those expressed in the forward-looking statements, see the cautionary statement concerning forward-looking statements on page ii.

Executive summary

Key consolidated financial data

		2017	2016	2015
		(€ million)		
Net sales from operations from continuing operations		66,919	55,762	72,286
Operating profit (loss) from continuing operations		8,012	2,157	(3,076)
Net profit (loss) attributable to Eni from continuing operations		3,374	(1,051)	(7,952)
Net profit (loss) attributable to Eni from discontinued operations			(413)	(826)
Net profit (loss) attributable to Eni		3,374	(1,464)	(8,778)
Net cash provided by operating activities – continuing operations		10,117	7,673	12,875
Capital expenditures – continuing operations		8,681	9,180	10,741
Disposal of assets, consolidated subsidiaries and businesses		5,455	1,054	2,258
Shareholders' equity including non-controlling interest at year end		48,079	53,086	57,409
Net borrowings at year end		10,916	14,776	16,871
Net profit (loss) attributable to Eni basic and diluted from continuing operations	(€ per share)	0.94	(0.29)	(2.21)
Dividend per share	(€ per share)	0.80	0.80	0.80
Ratio of net borrowings to total shareholders' equity including non-controlling interest (leverage)(1)		0.23	0.28	0.29

(1)
For a discussion of the usefulness and a reconciliation of these non-GAAP financial measures with the most directly comparable GAAP financial measures see – "Liquidity and capital resources – Financial Conditions" below.

Reported earnings

Net profit attributable to Eni's shareholders for the full year of 2017 was €3,374 million, a noticeable improvement over 2016, when a loss of €1,464 million was incurred from both continuing and discontinued operations, with the latter due to a charge on the Saipem shareholding following the loss of control over the investee. The reported operating profit for the full year of 2017 was €8,012 million, sharply higher than in 2016 (up by €5,855 million). The Eni Group recorded a substantial recovery in profitability across all business segments. This trend benefitted from higher commodity prices and margins and the progress in implementing the Group's strategy driven by a faster time-to-market of discoveries, profitable production growth, efficiency gains, restructuring of the long-term gas contracts portfolio, as well as the restructuring of refining and petrochemical hubs.

Leveraging on the turnaround achievements, Eni was able to fully capture an ongoing recovery in the oil price scenario, with Brent crude oil prices up by 24% y-o-y driven by better market fundamentals. The downstream businesses were helped by higher global demand for commodities.

The 2017 result was also helped by the net gains of €2,739 million recorded on the divestment of a 40% interest in the Zohr gas field offshore Egypt and of a 25% interest in natural gas-rich Area 4 offshore Mozambique, which effect was offset for two thirds by the recognition of a number of special charges and write-downs. Finally, the Group profit & loss benefitted from a lower tax rate of 51% in line with the

TABLE OF CONTENTS

Group historical average, while in 2016 the tax rate was much higher at 217%. This trend was explained by the recovery in profit before taxes of the E&P segment, which helped the Company offset against the taxable income a higher share of deductible expenses, including those incurred under PSA contracts, and to dilute the incidence of non-deductible expenses.

Adjusted results

Adjusted operating profit and adjusted net profit are determined by excluding inventory holding gains or losses and extraordinary and non-recurring gains and losses (pre and post-tax, respectively).

Adjusted operating profit (or loss) and adjusted net profit (or loss) provide management with an understanding of the results from our base operations by excluding the effects of certain disposals and special charges or gains that do not reflect the ordinary results of our operations. Adjusted measures of profitability are used to evaluate our period-over-period operating performance, as management believes these provide more comparable measures as they adjust for disposals and special charges or gains not reflective of the normal trend results of our business. These Non-GAAP performance measures may be useful to an investor in evaluating the underlying operating performance of our business, because the items excluded from the calculation of such measures can vary substantially from company to company depending upon accounting methods, management's judgement, book value of assets, capital structure and the method by which assets were acquired, among other factors.

In 2017, gains on disposals, asset revaluations, impairment losses, inventory holding profit or losses and other special charges were a net positive of €995 million in net profit and of €2,209 million in operating profit. Excluding these gains/charges, the adjusted net profit for the year was €2,379 million compared to a loss of €340 million in 2016, while the Group adjusted operating profit was €5,803 million, more than doubling from 2016 when adjusted operating profit was €2,315 million. The €3.5 billion increase of adjusted operating profit was explained for €3.1 billion by price and margins increases driven by the improved commodity environment and for €0.6 billion by volumes growth and efficiency and optimization gains, partly offset by OPEC cuts and one-off effects amounting to €0.2 billion.

The Group underlying performance – i.e net of non-recurring or extraordinary gains and losses and the inventory holding gain or losses – was driven by an improved performance in the E&P segment that doubled its operating profit at €5,173 million. This was due to higher hydrocarbons prices, production growth, capital and cost discipline and continued exploration success. Hydrocarbons production was 1.719 mmBOE/d, growing by 2.9% y-o-y.

The G&P segment reverted to profit after many years of unprofitable performances at €214 million leveraging on the renegotiation of long-term gas supply contracts, lower logistic costs and better results at the LNG, trading and power businesses.

The R&M and Chemical segment reported the best performance in years at €991 million (up by 70% y-o-y) driven by a recovery in commodity margins and the benefits of the restructuring plan of refineries and petrochemical hubs, cost efficiencies and the shift in the product mix towards specialties and higher value-added products (green fuels and chemicals). Those developments helped the business leverage an improved trading environment.

TABLE OF CONTENTS

The table below sets forth for the reported periods details of certain, identified gains and charges included in the net results.

	Year ended December 31,		
Eni Group	2017	2016	2015
	(€ million)		
(Profit) loss on inventory	(219)	(175)	1,136
Environmental provisions	208	193	225
Impairment losses (impairments reversals), net	(221)	(459)	6,534
Impairment of exploration projects		7	169
Net gains on disposal of assets	(3,283)	(10)	(407)
Risk provisions	448	151	211
Provision for redundancy incentives	49	47	30
Fair value gains/losses on commodity derivatives	146	(427)	164
Reclassification of currency derivatives and translation effects to management measure of business performance	(248)	(19)	(63)
Estimate revision of revenues accrued in the gas retail business	64	161	484
Valuation allowance of doubtful accounts(1)	616	410	
Write-off of the damaged units of the EST conversion plant at the Sannazzaro refinery		193	
Provision for removal and clean-up of EST conversion plant		24	
Compensation gain on part of a third-party insurer relating to the EST plant incident		(217)	
Other	231	279	301
Total net charges (gains) in operating profit	(2,209)	158	8,784
Finance expenses	502	116	286
of which: reclassification of currency derivatives and translation effects to management measure of business performance	248	19	63
Capital gains on disposal of investments	(163)	(57)	(33)
Write downs of investments and financing receivables	537	483	506
Write down of deferred tax assets/utilization of deferred tax liabilities		170	1,740
Tax effects relating to the US tax reform	115		
Tax effects on the above listed items and other items	160	(214)	(1,607)
Tax effects on (profit) loss on inventory	63	55	(354)
Net (charges) gains in net profit	(995)	711	9,322
Net (charges) gains attributable to non-controlling interest			53
Net (charges) gains attributable to Eni	(995)	711	9,269

(1)
Includes credit losses in E&P for receivables in Nigeria and Venezuela and in the retail G&P business for the estimate made in accordance with the expected loss accounting model net of the estimate made in accordance to the incurred

loss accounting for credit losses.

TABLE OF CONTENTS

The table below provides a reconciliation of those Non-GAAP measures to the most comparable performance measures calculated in accordance with IFRS.

	Year ended December 31,		
	2017	2016	2015
	(€ million)		
GAAP measure of operating profit	8,012	2,157	(3,076)
Inventory holding (gains) and losses	(219)	(175)	1,136
Identified net (gains) losses(1)	(1,990)	333	6,426
Non-GAAP measure of operating profit	5,803	2,315	4,486
GAAP measure of net profit	3,374	(1,051)	(7,952)
Inventory holding (gains) and losses, post tax	(156)	(120)	782
Identified net (gains) losses, post tax(1)	(839)	831	7,973
Non-GAAP measure of net profit	2,379	(340)	803

(1)
2015 data includes elimination upon consolidation of intercompany transactions with discontinued operations.

In 2017, net cash provided by operating activities amounted to €10,117 million. The closing of the divestment of Eni's assets in Mozambique and Egypt and other disposals generated €5,455 million of proceeds. These inflows funded financial requirements for capital expenditures (€9,191 million including investments) and the payment of Eni's dividend (the final dividend for fiscal year 2016 and the 2017 interim dividend totaling €2,880 million). Management also assessed the Group net cash provided by operating activities excluding movements in working capital net of the inventory holding gain, which resulted in €8,458 million. This cash flow was negatively impacted by:
(i)
Credit losses amounting to €616 million which included the recognition of a valuation allowance for doubtful accounts of our E&P business in connection with receivables in Nigeria and Venezuela, and the difference between the allowance for doubtful accounts made in accordance to the "expected loss" accounting model vs. the incurred loss accounting in the retail G&P business. The expected loss accounting model is due to be adopted in the statutory accounts starting from 2018;

(ii)
an extraordinary payment made for a tax settlement in Angola (€150 million) relating to past reporting periods.

Management assessed the progress made in 2017 to lower the Brent price level at which the Group was able to fund its capital expenditures and dividend payments through cash flow from operations. To that end it is worth noting that the disposals of a 40% interest in the Zohr gas field and of a 25% interest in Area 4 in Mozambique had retroactive economic effects, which means that the consideration received from the buyers included the reimbursement of the capex incurred by Eni in connection with those interests from the beginning of 2017 up to the completion date. Furthermore, Eni cashed in approximately €0.2 billion of advances in connection with future supplies of gas to our state-owned partners in Egypt as part of the agreements to accelerate the development plans of the Zohr gas field. Cash flow from operating activities including changes in working capital was netted of these advances and other minor items to €9.99 billion, whereas capex for the FY 2017 was netted of the share reimbursed by the buyers of the minority interests in the Zohr and Mozambique projects and other minor items to €7.62 billion, respectively, yielding a surplus of approximately €2.4 billion, which funded approximately 80% of the total amount of the cash dividend (€2.9 billion). Consequently, on the basis of the Group cash flow sensitivity to the Brent scenario which is assuming an increase of approximately €0.2 billion in cash flow for each one-dollar increase in the Brent price (and vice versa), the organic cash neutrality for funding FY capex and the floor dividend would have been achieved at 57$/ BBL, better than management's expectations at 60$/ BBL and in line with the long-term Company's target of a cash neutrality structurally below the 60$/BBL threshold. Going forward we will seek to further drive lower our cash neutrality.

At December 31, 2017, the Group's net debt decreased by €3,860 million to €10,916 million. The Group ratio of finance debt to total equity at year-end 2017 was 0.51. However, in assessing the Group financial structure, management is using a measure of indebtedness which subtracts cash and cash equivalents and other very liquid financial assets from finance debt. This Non-GAAP measure of

TABLE OF CONTENTS
indebtedness is defined “net borrowings” (see Glossary). The ratio of net borrowings to total equity is defined “Leverage” (see Glossary) and is commonly used by management in assessing the Group financial condition (see paragraph “Financial condition” below). Leverage at year-end 2017 decreased to 0.23 down from 0.28 at the end of 2016.
In 2018, we are projecting a capital expenditures budget of approximately €7.7 billion and a production growth rate of approximately 4% compared to 2017. Finally, we are projecting a cash dividend for the full year 2018 of €0.83 per share. See “Management expectations of operations”.
Trading environment

	2017	2016	2015
Average price of Brent dated crude oil in U.S. dollars(1)	54.27	43.69	52.46
Average price of Brent dated crude oil in euro(2)	48.03	39.47	47.26
Average EUR/USD exchange rate(3)	1.130	1.107	1.110
Standard Eni Refining Margin (SERM)(4)	5.0	4.2	8.3
Euribor – three month euro rate %(3)	(0.33)	(0.26)	(0.02)

(1)
Price per barrel. Source: Platt’s Oilgram.

(2)
Price per barrel. Source: Eni’s calculations based on Platt’s Oilgram data for Brent prices and the EUR/USD exchange rate reported by the European Central Bank (ECB).

(3)
Source: ECB.

(4)
In $/BBL FOB Mediterranean Brent dated crude oil. Source: Eni calculations. Approximates the margin of Eni’s refining system in consideration of material balances and refineries’ product yields.

When the term margin is used in the following discussion, it refers to the difference between the average selling prices and reflects the trading environment and are, to a certain extent, a gauge of industry profitability.
Eni’s results of operations and the year-to-year comparability of its financial results are affected by a number of external factors which exist in the industry environment, including changes in oil, natural gas and refined products prices, industry-wide movements in refining margins and fluctuations in exchange rates and interest rates. Changes in weather conditions from year to year can influence demand for natural gas and some petroleum products, thus affecting results of operations of the natural gas business and, to a lesser extent, of the refining and marketing business. See “Item 3 – Risk factors”.
In 2017, the trading environment was characterized by a recovery in crude oil prices, particularly in the last part of the year. This was driven by a better balance between global demand and supplies on the back of the agreement reached by OPEC Countries at the end of November 2016 to reduce the output of the cartel, joined also by certain non OPEC countries (among which Russia). The average price for the Brent crude oil benchmark increased by 24% y-o-y. This recovery was not fully reflected in Eni’s average hydrocarbon realizations because of the slow recovery of gas realizations on equity production, also reflecting time lags in oil-linked price formulas.
Eni’s refining margins (Standard Eni Refining Margin – SERM) which represents the benchmark for the level of profitability of Eni’s refineries before fixed cash expenses, increased from a year ago (up by 19%) to 5 $/BBL benefitting from higher relative prices of products compared to the cost of the petroleum feedstock. This trend has weakened in the fourth quarter 2017 due to a swift upward movements in the Brent price. The Company managed to

reduce its breakeven margin and to align it with the current trading environment.

The exchange rate of euro against the dollar was 1.130, with an appreciation of 2.1% compared to the average exchange rate recorded in 2016.

Critical accounting estimates

The preparation of the Consolidated Financial Statements requires the use of estimates and assumptions that affect the carrying amounts of assets and liabilities, revenues and expenses reported in the financial statements, as well as amounts included in the notes thereto, including discussion and disclosure

TABLE OF CONTENTS

of contingent liabilities. Estimates made are based on complex or subjective judgments and past experience or other assumptions deemed reasonable in consideration of the information available at the time. The accounting policies and areas that require the most significant judgments and estimates to be used in the preparation of the Consolidated Financial Statements are in relation to the accounting for oil and natural gas assets, specifically in the determination of proved and proved developed reserves, impairment of fixed assets, intangible assets, equity-accounted investments and goodwill, decommissioning and restoration liabilities, business combinations, pensions and other post-retirement benefits, and recognition of environmental liabilities. Although the Company uses its best estimates and judgments, actual results could differ from the estimates and assumptions used. A summary of significant estimates is provided in "Item 18 – note 6 – of the Notes on Consolidated Financial Statements".

2015 – 2017 Group results of operations

Overview of the profit and loss account for three years ended December 31, 2015, 2016 and 2017

The table below sets forth a summary of Eni's profit and loss account for the periods indicated. All line items included in the table below are derived from the Consolidated Financial Statements prepared in accordance with IFRS.

	Year ended December 31,		
	2017	2016	2015
	(€ million)		
Net sales from operations	66,919	55,762	72,286
Other income and revenues(1)	4,058	931	1,252
Total revenues	70,977	56,693	73,538
Operating expenses	(55,412)	(47,118)	(59,967)
Other operating (expense) income	(32)	16	(485)
Depreciation, depletion and amortization	(7,483)	(7,559)	(8,940)
Impairment reversal (impairment losses), net	225	475	(6,534)
Write-off	(263)	(350)	(688)
OPERATING PROFIT (LOSS)	8,012	2,157	(3,076)
Finance income (expense)	(1,236)	(885)	(1,306)
Income (expense) from investments	68	(380)	105
PROFIT (LOSS) BEFORE INCOME TAXES	6,844	892	(4,277)
Income taxes	(3,467)	(1,936)	(3,122)
Net profit (loss) – continuing operations	3,377	(1,044)	(7,399)
Net profit (loss) – discontinued operations		(413)	(1,974)
Net profit (loss)	3,377	(1,457)	(9,373)
Attributable to:			
Eni's shareholders:	3,374	(1,464)	(8,778)
- continuing operations	3,374	(1,051)	(7,952)
- discontinued operations		(413)	(826)
Non-controlling interest:	3	7	(595)
- continuing operations	3	7	553
- discontinued operations			(1,148)

(1)
Includes, among other things, contract penalties, income from contract cancellations, gains on disposal of mineral

rights and other fixed assets, compensation for damages and indemnities and other income.

The table below sets forth certain income statement items as a percentage of net sales from operations for the periods indicated.

	Year ended December 31,		
	2017	2016	2015
	(%)		
Operating expenses	82.8	84.5	83.0
Depreciation, depletion, amortization, impairments reversal (impairment losses), net, write-off	11.2	13.3	22.4
OPERATING PROFIT	12.0	3.9	(4.3)

2017 compared to 2016. See management discussion under paragraph "Executive summary" on page 99 for an overview of the Group's results from continuing operations. Net profit attributable to Eni's shareholders amounted to €3,374 million for 2017, an increase of €4,838 million compared to the net loss of €1,464 million reported in 2016.

2016 compared to 2015. Net loss attributable to Eni's shareholders including both continuing operations and discontinued operations amounted to €1,464 million for 2016. The loss of the discontinued operations pertaining to Eni's shareholders (€413 million) was affected by the recognition of a charge of €441 million due to the alignment of Eni's retained interest in Saipem with its market value the date of the loss of control (January 22, 2016). The market value of the retained interest in the former subsidiary was the carrying amount of such interest upon initial recognition for the subsequent accounting under the equity method (€564 million to which a share capital increase of €1,069 million is to be added).

Discontinued operations

The table below sets forth net profit (loss) attributable to discontinued operations for the periods indicated.

	Year ended December 31,		
	2017	2016	2015
	(€ million)		
Net profit – discontinued operations		(413)	(1,974)
attributable to:			
- Eni		(413)	(826)
- non-controlling interest			(1,148)

Based on the accounting of IFRS 5 for disposal groups, gains and losses pertaining to the discontinued operations include only those earned from transactions with third parties. Until such time as Saipem was a subsidiary of the Eni Group (i.e. end of the reporting period 2015), gains and losses on intercompany transactions have been eliminated upon consolidation. These comprised mainly revenues earned by Saipem for the supply of capital goods and maintenance services to Eni's Group companies, which were eliminated upon consolidation, positively affecting results of the continuing operations, while negatively affecting the results of operations of the discontinued operations. This effect did not recur in 2016 due to the derecognition of Saipem effective January 1, 2016. Furthermore, the 2015 loss from discontinued operations included the alignment of Saipem's net assets to its market capitalization at the balance sheet date leading to a loss of €393 million.

Analysis of the line items of the profit and loss account of continuing operations

a) Total revenues

Eni's revenues from continuing operations were €70,977 million, €56,693 million and €73,538 million for the years ended December 31, 2017, 2016 and 2015, respectively. Total revenues consist of net sales from operations and other income and revenues. Eni's net sales from operations from continuing operations amounted to €66,919 million, €55,762 million and €72,286 million for the year ended December 31, 2017, 2016 and 2015, respectively, and its other income and revenues totaled €4,058 million, €931 million and €1,252 million, respectively, in these periods.

105

TABLE OF CONTENTS

Net sales from operations from continuing operations

The table below sets forth, for the periods indicated, net sales from operations from continuing operations generated by each of Eni's business segments including intragroup sales, together with consolidated net sales from operations.

	Year ended December 31,		
	2017	2016	2015
	(€ million)		
Exploration & Production	19,525	16,089	21,436
Gas & Power	50,623	40,961	52,096
Refining & Marketing and Chemicals	22,107	18,733	22,639
Corporate and other activities	1,462	1,343	1,468
Consolidation adjustments(1)	(26,798)	(21,364)	(25,353)
NET SALES FROM OPERATIONS FROM CONTINUING OPERATIONS	66,919	55,762	72,286

(1)
Intragroup sales are included in net sales from operations in order to give a more meaningful indication as to the volume of the activities to which sales from operations by segment may be related. The largest intragroup sales are recorded by the Exploration & Production segment. "Item 18 – note 46 – of the Notes on Consolidated Financial Statements for a breakdown of intragroup sales by segment for the reported years.

2017 compared to 2016. Eni's net sales from operations (revenues) from continuing operations for 2017 (€66,919 million) increased by €11,157 million from 2016 (or up by 20%) primarily reflecting higher realizations on oil, products and natural gas due to the recovery in commodity prices. Changes in sales volumes of products sold were immaterial.

Revenues generated by the Exploration & Production segment (€19,525 million) increased by €3,436 million (or up by 21.4%). This was due to higher average realizations on equity hydrocarbons (up by 20.3% on average in dollar terms) driven by increasing prices for the marker Brent (up by 24.2%) and gas benchmarks in Europe, in the United States and elsewhere which however appreciated by a smaller amount than oil realizations due to time lags in oil-linked pricing formulas.

Revenues generated by the Gas & Power segment (€50,623 million) increased by €9,662 million (or up by 23.6%). The increase reflected higher commodity prices and volumes purchased to be resold in the business of crude oil and refined products trading, as well as higher gas and power selling prices.

Revenues generated by the Refining & Marketing and Chemical segment (€22,107 million) increased by €3,374 million (or up by 18%) mainly reflecting a recovery in the commodities prices. The average selling prices of gasoline and gasoil reported an increase of 19% and 24%, respectively. The average selling prices in the Chemical business increased by 16% due to the recovery in the monomers (intermediates up by 27% and polymers up by 13%).

2016 compared to 2015. Eni's net sales from operations (revenues) from continuing operations for 2016 (€55,762 million) decreased by €16,524 million from 2015 (or down by 22.9%) primarily reflecting lower realizations on oil, products and natural gas due to significantly lower commodity prices. Changes in sales volumes of products sold were immaterial.

Revenues generated by the Exploration & Production segment (€16,089 million) decreased by €5,347 million (or down by 24.9%). This was due to lower average realizations on equity hydrocarbons (down by 20.1% on average in dollar terms) driven by declining prices for the marker Brent (down by 16,7%) and gas benchmarks in Europe, in the United States and elsewhere also considering the time lags in oil-linked formulas. The reduction was also negatively affected by the Val d'Agri shutdown, which lasted four and half months. The negative price impact was mainly recorded at concession contracts, while PSA contracts are insulated from the scenario due to the cost recovery mechanism.

Revenues generated by the Gas & Power segment (€40,961 million) decreased by €11,135 million (or down by 21.4%). The reduction reflected lower gas and power selling prices as well as lower commodity prices in the business of crude oil and refined products trading, which impact was however offset at the

106

TABLE OF CONTENTS

operating profit level by a corresponding decrease in the supply costs of the commodities. Furthermore, revenues were also negatively affected by a downward revision of revenues accrued on the sale of gas and power to retail customers in Italy (€161 million) dating back to past reporting periods prior to 2015.

Revenues generated by the Refining & Marketing and Chemical segment (€18,733 million) decreased by €3,906 million (or down by 17.3%) mainly reflecting lower average selling prices driven by weaker commodity prices. The average selling prices in the Chemical business declined by 10% due to lower price of polymers (down by 6.7% and down by 6.3% the average price of elastomers and styrenics, respectively), reflecting the impact of scenario and competitive pressure.

Other income and revenues from continuing operations

2017 compared to 2016. Eni's other income and revenues from continuing operations for 2017 (€4,058 million) increased by €3,127 million from 2016 primarily reflecting gains on the disposal of a 40% interest in the Zohr gas field in Egypt (€1,281 million) and of a 25% interest in natural gas-rich Area 4 offshore Mozambique (€1,985 million).

2016 compared to 2015. Eni's other income and revenues from continuing operations for 2016 (€931 million) decreased by €321 million from 2015 (or down by 26%) primarily reflecting the circumstance that in 2015 the Group recorded gains on the disposal of non-strategic assets in the E&P segment, mainly in Nigeria.

b) Operating expenses

The table below sets forth the components of Eni's operating expenses for the periods indicated.

	Year ended December 31,		
	2017	2016	2015
	(€ million)		
Purchases, services and other	52,461	44,124	56,848
Payroll and related costs	2,951	2,994	3,119
Operating expenses	55,412	47,118	59,967

2017 compared to 2016. Operating expenses from continuing operations for 2017 (€55,412 million) increased by €8,294 million y-o-y, up by 17.6%, primarily reflecting higher supply costs of raw materials (natural gas under long-term supply contracts, refinery and chemical feedstock and hydrocarbons purchased for resale). Purchases, services and other costs included €660 million relating mainly to environmental provisions and the recognition of losses on certain contractual and commercial disputes (€360 million in 2016). Payroll and related costs (€2,951 million) decreased by €43 million from 2016, down by 1.4%, mainly due to the lower average number of employees and the appreciation of euro vs. the dollar and the GBP.

2016 compared to 2015. Operating expenses from continuing operations for 2016 (€47,118 million) decreased by €12,849 million y-o-y, down by 21.4%, primarily reflecting lower supply costs of raw materials (natural gas under long-term supply contracts, refinery and chemical feedstock and hydrocarbons purchased for resale). Purchases, services and other costs included €360 million relating mainly to environmental provisions (€436 million in 2015). Payroll and related costs (€2,994 million) decreased by €125 million from 2015, down by 4%, due to lower average number of employees outside Italy.

TABLE OF CONTENTS

c) Depreciation, depletion, amortization, impairments (impairment reversals) net and write-off

The table below sets forth a breakdown of depreciation, depletion, amortization, impairments (impairment reversals) net and write-off for the periods indicated.

	Year ended December 31,		
	2017	2016	2015
	(€ million)		
Exploration & Production	6,747	6,772	8,080
Gas & Power	345	354	363
Refining & Marketing and Chemicals	360	389	454
Corporate and other activities	60	72	71
Impact of unrealized intragroup profit elimination(1)	(29)	(28)	(28)
Total depreciation, depletion and amortization	7,483	7,559	8,940
Impairment losses	862	1,067	6,537
Reversals of impairment losses	(1,087)	(1,542)	(3)
Write-off	263	350	688
Total depreciation, depletion, amortization, impairment losses (impairment reversals), net and write off	7,521	7,434	16,162

(1)
This item concerned mainly intra-group sales of goods and capital, recorded at period end in the assests of the purchasing business segment.

2017 compared to 2016. In 2017, depreciation, depletion and amortization charges (€7,483 million) decreased by €76 million from 2016, or 1%, mainly in the Exploration & Production segment (with a decrease of €25 million) reflecting lower development capital expenditures of the year (down by 6.9%) and the euro appreciation, partially offset by start-ups and ramp-ups of new projects, and in the Refining & Marketing segment due to the write-off, reported in 2016, of the damaged units of the EST conversion plant following the accident occurred in December 2016.
In 2017, the Group recorded reversals of prior impairment losses in the E&P segment, at oil&gas properties for €808 million. These were driven by upward reserve revisions, lower future development and operating expenses, as well as a favourable impact in connection with the new corporate tax regime in the USA. The Gas & Power segment recorded the reversal of asset impairment losses recorded in previous reporting periods relating for €184 million to the alignment of the book value of the Hungarian gas distribution activity to its fair value, in light of a sale negotiation ongoing at the balance sheet date which may lead to a sale being completed in 2018. In the Refining & Marketing and Chemicals segment, an asset impairment reversal of €76 million reflected improved profitability prospects of the Chemical business. These reversals were partly offset by impairment losses relating to oil&gas properties in the upstream business (€650 million) driven by the project re-phasing or cancellation and downward reserve revisions. Finally, investments made for compliance and stay-in-business purposes were fully impaired at cash generating units previously written-off in the Refining & Marketing business, which were confirmed to lack any prospects of profitability (€130 million).
The write-off amounting to €263 million, mainly related to the costs of exploratory wells lacking the requisites for continuing capitalization because they did not encounter commercial quantities of hydrocarbons or due to lack of management commitment in pursuing further appraisal activity in Egypt, Norway and the Ivory Coast.
2016 compared to 2015. In 2016, depreciation, depletion and amortization charges (€7,559 million) decreased by €1,381 million from 2015, or 15.4%, mainly in the Exploration & Production segment (with a decrease of €1,308 million) reflecting lower capital expenditures of the year (down by 16.2%) and the lower carrying amounts of certain oil&gas

properties following the impairment losses booked in 2015 (€5,212 million).
In 2016, the Group recorded reversals of prior impairment losses at oil&gas properties for €1,440 million. These were determined by an upward revision to the long-term price of the benchmark Brent to 70 $/BBL, up from the previous 65 $/BBL assumption, which drove the financial projections of the

2017 – 2020 industrial plan and the recoverability of oil&gas assets carrying amounts in the 2016 financial statements. These reversals were partly offset by impairment losses related to gas properties in the upstream business driven by a lowered price outlook in Europe and other oil&gas properties due to contractual changes, reserves revision and a higher country risk (overall amount of €756 million). Finally, investments made for compliance and stay-in-business purposes were fully impaired at cash generating units previously written-off in the Refining & Marketing and Chemicals segment, which were confirmed to lack any prospects of profitability (€104 million), while the Gas & Power segment recorded an impairment loss of €81 million related to a gas transport infrastructure and LNG carriers.

The write-off amounting to €350 million, mainly related to the costs of exploratory wells lacking the requisites for continuing capitalization because they did not encounter commercial quantities of hydrocarbons or due to lack of management commitment. The item also comprised the write-off of the damaged units of the EST conversion plant at the Sannazzaro Refinery due to the accident occurred in December 2016 (€193 million).

d) Operating profit (loss) by segment

The table below sets forth Eni's operating profit from continuing operations by business segment for the periods indicated.

	Year ended December 31,		
	2017	2016	2015
	(€ million)		
Exploration & Production	7,651	2,567	(959)
Gas & Power	75	(391)	(1,258)
Refining & Marketing and Chemicals	981	723	(1,567)
Corporate and other activities	(668)	(681)	(497)
Impact of unrealized intragroup profit elimination	(27)	(61)	1,205
Operating profit (loss)	8,012	2,157	(3,076)

The table below sets forth operating profit (loss) from continuing operations for each of Eni's business segments as a percentage of each segment's net sales from operations from continuing operations (including intragroup sales) for the periods presented.

	Year ended December 31,		
	2017	2016	2015
	(%)		
Exploration & Production	39.2	16.0	(4.5)
Gas & Power	0.1	(1.0)	(2.4)
Refining & Marketing and Chemicals	4.4	3.9	(6.9)
Group	12.0	3.9	(4.3)

Exploration & Production. In 2017, the Exploration & Production segment reported an operating profit of €7,651 million, with an increase of €5,084 million compared to the operating profit of €2,567 million reported in 2016, due to an ongoing recovery in crude oil prices (the Brent benchmark in dollar terms was up by 24.2%; however, it was up by 21.7% in euro terms) and production growth. This result was also positively influenced by the net gains recorded on the disposal of a 40% interest in the Zohr asset (€1,281 million) and of a 25% interest in the exploration Area 4 offshore Mozambique (€1,985 million), the reversal of previously booked impairment losses at certain oil&gas CGUs driven by upward reserve revisions, updated projections of operating expenses and capital expenditures and the positive effect of the US tax reform. This gains were partially offset by impairment losses recorded at certain oil&gas projects in Venezuela and the related current trade receivables as discussed below, valuation allowances for doubtful accounts, as well as the recognition of losses on certain contractual and commercial disputes.

Eni is currently engaged in executing two large petroleum projects in Venezuela: the Perla offshore gas project operated by the local company Cardón IV, a 50-50 joint-venture with another international oil company, and the PetroJunín onshore oil project jointly operated with PDVSA according to regime of the

TABLE OF CONTENTS

"Empresa Mixta". Eni has invested approximately €1.5 billion to develop the two projects. Furthermore, a significant amount of overdue trade receivables was outstanding at the reporting date for the supply of the gas produced by the j.v. Cardón IV to PDVSA. Those trade receivables amounted to approximately €500 million before any valuation allowance and were held by both the venture and Eni's subsidiaries operating in the Country. With a view to incorporating the Venezuela counterparty risk and the uncertainty relating the possible evolution of the difficult financial condition of the Country in assessing the recoverability of the Company's investments and trade receivables, management has reviewed the empirical evidence and official statistics relating to the recent history of sovereign financial crises. Based on these findings and considering that Eni's gas supplies are strategic and vital to the Country, management elaborated a possible scenario of the evolution of the Venezuelan financial crisis to drive internal estimates of our assets recoverability in Venezuela. Furthermore, considering a deteriorating operational environment and the financial risks underlying assets' recoverability, management reclassified 315 mmBOE of undeveloped gas reserves to the unproved category, in accordance with the applicable US SEC regulation. These drivers led us to recognize asset impairment losses and a credit valuation allowance for a total amount of approximately €760 million.
Also Nigeria is experiencing a situation of financial stress which drove us to the recognition of significant credit losses. The amount of overdue receivables due to Eni at the balance sheet date was $1 billion which comprised the cash calls owed by the National oil Company "NNPC" at petroleum projects operated by Eni. Those receivables related to previous reporting periods. To collect those amounts Eni and its counterpart agreed upon a Repayment Agreement, whereby Eni expects to be reimbursed of the overdue amounts through the sale of the profit oil attributable to NNPC in certain rig-less petroleum initiatives which will be developed in future years. Those credits are stated in the financial statements net of a discount factor determined by utilizing the risk-adjusted weighted average cost of the capital to the Group to incorporate the mineral risk. NNPC has regularly funded the cash calls for the years 2016 and 2017, which led management to confirm the recoverability of the overdue cash calls. Other overdue credits were written down to reflect the counterparty risk in light of the deteriorated financial situation of the Country with a charge to profit of €258 million and related mainly to disputed receivables for cost recovery, considering lack of any progress in the course of the year to agree on a repayment plan.
In 2017, the Company's liquids and gas realizations increased on average by 20.3% in dollar terms, driven by an increase in international oil prices for market benchmarks (Brent crude prices increased by 24.2%). Eni's average oil realizations increased on average by 27.8%. Eni's average gas realizations increased only by 12.8% because of time lags in oil-linked formulas.
In 2016, the Exploration & Production segment reported an operating profit of €2,567 million, with an increase of €3,526 million from the operating loss of €959 million reported in 2015. This change mainly reflected the impairment charges of €5,212 million recorded in 2015 due to a downward revision of the oil scenario, while in 2016 net impairment reversals of €684 million were recorded due to a hike in management long-term oil price assumptions.
In 2016, the Company's liquids and gas realizations decreased on average by 20.1% in dollar terms, driven by a decline in international oil prices for market benchmarks (Brent crude prices decreased by 16.7%). Eni's average oil realizations decreased on average by 15.4%. Eni's average gas realizations decreased by 28.2% and were negatively impacted by the weak scenario and time lags in oil-linked formulas.
In reviewing the performance of the Company's business segments and with a view to better explaining year-on-year changes in the segment performance, management generally excludes the gains and losses presented below in order to assess the underlying industrial trends and obtain a better comparison of core business performance across reporting periods. Excluding the below-listed gains and charges, the E&P segment reported a Non-GAAP operating profit of €5,173 million, with an increase of €2,679 million from 2016, or 107.4%. The increase was driven by a recovery in the commodity environment which drove increased oil&gas realizations in dollar terms (up by 20.3% on average) and production growth. These positives were partly offset by higher write-offs of unsuccessful exploratory wells and higher expenses.

	Year ended December 31,		
	2017	2016	2015
Exploration & Production	(€ million)		
GAAP operating profit (loss)	7,651	2,567	(959)
Net gains on disposal of assets	(3,269)	(2)	(403)
Impairment losses (impairment reversals), net	(158)	(677)	5,381
Environmental provisions	46		
Risk provisions	366	105	
Reclassification of currency derivatives and translation effects to management measure of business performance	(68)	(3)	(59)
Valuation allowance of disputed receivables and others	442	410	
Other	163	94	222
Total gains and charges	(2,478)	(73)	5,141
Non-GAAP operating profit (loss)	5,173	2,494	4,182

Gas & Power. In 2017, the Gas & Power segment reported an operating profit of €75 million, improving by €466 million compared to 2016 when the segment reported an operating loss of €391 million. This result was driven by the economic benefits from the renegotiation of gas supply contracts as well as lower logistic costs and improved performance in trading, LNG and Power businesses. Result also includes the reversal of asset impairment losses recorded in previous reporting periods for €146 million, mainly relating to the alignment of the book value of the Hungarian gas distribution activity to its fair value, in light of a sale negotiation ongoing at the balance sheet date which may lead to a sale being completed in 2018. Furthermore, from 2017, the profit/loss on stock has been included in the business underlying performance due to a changed regulatory framework on gas storage in Italy, on which basis management has elected to leverage gas stocks as a way to improve margins.

These positives were partly offset by lower gains in connection with the effects of fair-valued commodity derivatives that lacked the formal criteria to be accounted as hedges under IFRS.

In 2016, the Gas & Power segment reported an operating loss of €391 million, improving by €867 million compared to 2015 when the segment reported an operating loss of €1,258 million. The 2015 result was negatively affected by a downward estimate revision of revenues accrued on the sale of gas and power (€484 million) to retail customers in Italy dating back to past reporting periods and the establishment of a provision for the above mentioned accruals (€226 million). In 2016, accrued revenues were revised lower by €161 million relating reporting periods prior to 2015. Furthermore, commodity derivatives lacking criteria for being accounted as hedges generated approximately €500 million of higher gains in 2016.

In reviewing the performance of the Company's business segments and with a view to better explaining year-on-year changes in the segment performance, management generally excludes the gains and losses presented below in order to assess the underlying industrial trends and obtain a better comparison of base business performance across reporting periods. Excluding the below-listed gains and charges, the G&P segment reported a Non-GAAP operating profit of €214 million, with an increase of €604 million from 2016, reflecting the benefits of the renegotiation process of long-term contracts, lower logistic costs and a better performance of the LNG, retail and trading businesses.

The items excluded from GAAP operating profit in determining the Non-GAAP measure of profitability mainly include certain commodity fair-valued derivatives and accruals measurements. Particularly, we enter into commodity and currency derivatives to reduce our exposure to (i) the commodity risk due to different indexation between the purchase cost and the selling price of gas and power or to lock in a commercial margin once a sale contract has been signed or it is highly probable, and (ii) the underlying exchange rate risk due to the fact that our selling prices are indexed to the euro and our supply costs are denominated in dollars. These derivatives normally hedge net Group exposure to commodities and exchange rates but do not meet the requirements for being accounted as hedges in accordance to IFRS. Therefore, in explaining year-on-year charges and in evaluating the business performance management believes that is appropriate to identify the fair value of commodity derivatives because they relate to transactions that will close in subsequent reporting periods or we estimate the portion of gains and losses on the settlement of certain commodity derivatives where underlying physical transaction has yet to be settled with the delivery of the underlying commodity. Furthermore, albeit the Group classifies within net finance expense those gains and losses on currency derivatives, as well as on the alignment of trade

TABLE OF CONTENTS
receivable and payables denominated in dollars into the accounts of euro subsidiaries at the closing rate, we believe that it is appropriate to consider those gains and losses on currency derivatives and alignment differences of our trade payables and receivables as part of the underlying business performance. Other special gains or losses comprise the re-measurement of revenues accrued in the retail gas and power business because they relate to past reporting periods. Finally, from 2017 management has excluded from GAAP operating profit the difference between the allowance for doubtful accounts incurred in the reporting period and the amount of credit loss determined in accordance to the expected loss model.
From 2017, the recognition of the inventory holding (gains) losses has been discontinued in the Gas & Power segment adjusted result considering that inventory levels have been minimized and the fact that management is leveraging inventories to improve margins.

	Year ended December 31,		
	2017	2016	2015
Gas & Power	(€ million)		
GAAP operating profit (loss)	75	(391)	(1,258)
(Profit) loss on inventory		90	132
Impairment losses (impairment reversals), net	(146)	81	152
Allowance for doubtful accruals in the retail G&P		17	226
Provision for redundancy incentives	38	4	6
Fair value gains/losses on commodity derivatives	157	(443)	90
Reclassification of currency derivatives and translation effects to management measure of business performance	(171)	(19)	(9)
Estimate revision of revenues accrued in the retail G&P	64	161	484
Revision of estimated revenues accruals in the retail G&P (difference between incurred loss vs. expected loss model)	223		
Other	(26)	110	51
Total gains and charges	139	1	1,132
Non-GAAP operating profit (loss)	214	(390)	(126)

TABLE OF CONTENTS

Refining & Marketing and Chemicals. In 2017, the Refining & Marketing and Chemicals segment reported an operating profit of €981 million, with an improvement of €258 million y-o-y, driven by higher refining margins, particularly in the nine months of the year, and which also benefitted from the restructuring of Eni refineries and petrochemicals hubs implemented over the latest years. Refinery optimization helped Eni to reduce the break-even margin below the 4 $/ BBL threshold and capture the upside in the scenario recorded in the first nine months of 2017. Operating profit included also the gain from the licensing of the EST conversion technology to Sinopec. These positives were partly offset by lower plant availability at the Sannazzaro refinery in connection with the shutdown of the EST unit, which is undergoing a rebuilding. The marketing business performed well due to effective commercial initiatives, mainly in the segment of premium products and services.

In the Chemical business, the optimized plant setup at core hubs and the focus of the product portfolio towards higher-value segments enabled the company to leverage the upside in the trading environment and to achieve volume upsides.

Better industrial trends were partly offset by a lower inventory gain.

In 2016, the Refining & Marketing and Chemicals segment reported an operating profit of €723 million, reversing an operating loss of €1,567 million reported in 2015. The improvement of €2,290 million was mainly due to lower assets impairments because a €1 billion charge was recognized in 2015 at the Chemical business to align its carrying amount with the expected fair value based on a sale transaction then ongoing designed to establish an industrial joint venture. Furthermore, in 2015 an inventory write-down of €877 million (pre-tax) was accounted for in the profit and loss because of the fall in oil commodity prices to align the net realizable value of the inventories to prices current at the balance sheet date. In 2016, following a late-year recovery in price scenario, the write down resulted in a gain on stock. The 2016 operating profit in the Refining & Marketing and Chemicals segment was also negatively affected by the write-off related to the EST conversion plant, at Sannazzaro Refinery, following an event occurred in December 2016, and the provision for removal and clean-up (a total amount of €217 million), partially offset by the recognition of third-party insurance compensation (€122 million)

The main item excluded from GAAP operating profit in determining the Non-GAAP measure of profitability is the inventory holding gain (or loss). Inventory holding gains or losses represent the difference between the cost of sales of the volumes sold during the period calculated using the cost of supplies incurred during the same period and the cost of sales calculated using the weighted average cost method. Under the weighted average cost method, which we use for IFRS reporting, the cost of inventory charged to the income statement is based on its historic cost of purchase, or manufacture, rather than its replacement cost. In volatile energy markets, this can have a significant impact on reported income thereby affecting comparability. The amounts disclosed represent the difference between the charge (to the income statement) for inventory on a weighted average cost method basis (after adjusting for any related movements in net realizable value provisions) and the charge that would have arisen if an average cost of supplies was used for the period. For this purpose, the average cost of supplies during the period is principally calculated on a quarterly or monthly basis by dividing the total cost of inventory acquired in the period by the number of barrels acquired. The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions. We regard the inventory holding gain or loss, including any write-down to align the carrying amounts of inventories to their net realizable value at the reporting date, as lacking correlation to the underlying business performance which we track by matching revenues with current costs of supplies.

TABLE OF CONTENTS

In reviewing the performance of the Company's business segments and with a view to better explaining year-on-year changes in the segment performance, management generally excludes the inventory holding gain (or loss) and the other gains and losses presented below in order to assess the underlying industrial trends and obtain a better comparison of base business performance across reporting periods. Excluding the below-listed gains and charges, the R&M and Chemical segment reported a Non-GAAP operating profit of €991 million, with an increase of €408 million from 2016. The segment base performance in 2017 benefited from the industrial trends outlined above and of a better trading environment.

	Year ended December 31,		
	2017	2016	2015
Refining & Marketing and Chemicals	(€ million)		
GAAP operating profit (loss)	981	723	(1,567)
(Profit) loss on inventory	(213)	(406)	877
Environmental provisions	136	104	137
Impairment losses (impairment reversals), net	54	104	1,150
Net gains on disposal of assets	(13)	(8)	(8)
Provision for redundancy incentives	(6)	12	8
Other	52	54	98
Total gains and charges	10	(140)	2,262
Non-GAAP operating profit (loss)	991	583	695

R&M and Chemicals: charges were mainly composed of the write down of capital expenditures relating to certain Cash Generating Units in the refining business, which were impaired in previous reporting periods and continued to lack any profitability prospects (€130 million) and environmental provisions (€111 million). The Chemicals business recorded the reversal of an asset impairment for €76 million due to improved profitability prospects of the single Cash Generation Unit of the Chemical business, environmental provisions and restoration costs incurred at industrial hubs which were restructured (€48 million) and impairment losses of an investment and of the financing receivables due by an industrial joint venture because of lower profitability prospects (€207 million).

Corporate and Other activities. These activities are mainly cost centers comprising holdings and treasury, headquarters, central functions like information technology, human resources, self-insurance activities, as well as the Group environmental clean-up and remediation activities performed by the subsidiary Syndial.

The aggregate Corporate and Other activities reported an operating loss of €668 million in 2017 representing an increase of €13 million from 2016, or 1.9%, mainly reflecting the recognition of risk provisions related to environmental issues and other, that were partly offset by the implementation of cost efficiency measures.

The aggregate Corporate and Other activities reported an operating loss of €681 million in 2016 representing an increase of €184 million from 2015, or 37%, mainly reflecting the recognition of risk provisions related to environmental issues and other that were partly offset by the implementation of cost efficiency measures.

TABLE OF CONTENTS

e) Net finance expenses

The table below sets forth a breakdown of Eni's net financial expenses for the periods indicated:

	Year ended December 31,		
	2017	2016	2015
	(€ million)		
Gain (loss) on derivative financial instruments	837	(482)	160
of which			
– Derivatives on exchange rate	809	(494)	96
– Derivatives on interest rate	28	(12)	31
Exchange differences, net	(905)	676	(354)
Net income from financial activities held for trading	(111)	(21)	3
Interest income	12	15	19
Finance expense from banks on short and long-term debt	(751)	(757)	(838)
Finance expense due to the passage of time (accretion discount)	(264)	(312)	(291)
Other finance income and expense, net	(127)	(110)	(171)
	(1,309)	(991)	(1,472)
Finance expense capitalized	73	106	166
	(1,236)	(885)	(1,306)

2017 compared to 2016. In 2017, net finance expenses were €1,236 million, down by €351 million compared to 2016 reflecting the recording of currency losses partly offset by positive fair value adjustments on currency derivatives (for a net negative effect of €278 million), with the latter lacking the formal criteria to be designated as hedges under IFRS. Furthermore, a loss from financial activities held for trading (€111 million) was recorded due to the translation differences, which were offset by a corresponding gain on exchange derivatives that did not satisfy the criteria for hedge accounting. Other net finance income and expense, referred to the impairment of operating financing receivables.

2016 compared to 2015. In 2016, net finance expenses were €885 million, down by €421 million compared to 2015 reflecting the recording of currency gains partly offset by negative fair value adjustments on currency derivatives (for a net positive effect of €440 million), with the latter lacking the formal criteria to be designated as hedges under IFRS. Furthermore, lower finance expense on debt were recorded due to the reduction in net borrowings and to lower interest rates reflecting accommodative monetary policies adopted by the Central Banks worldwide. These positives were partly offset by impairment losses on certain financing receivables granted to equity-accounted entities which are currently executing industrial projects on Eni's behalf (€121 million). Furthermore, a discount expense of €129 million was recognized relating to certain receivable in the E&P segment owed by certain NOCs due to agreements to repay the overdue amount in instalments with the proceeds associated with mineral initiatives. On that basis, the discount rate utilized reflected also the mineral risk.

f) Net income from investments

2017 compared to 2016. In 2017 the Group reported a net profit from investments of €68 million related to:

(i)
dividends received from entities accounted for at cost (€205 million) relating to Nigeria LNG Ltd (€167 million) and Saudi European Petrochemical Co (€21 million);

(ii)
net gains on the divestment of interests (€163 million) mainly relating to the disposal of the Gas & Power retail activity in Belgium.

These positives were partly offset by:

(i)

a loss of €267 million recorded on equity-accounted entities, mainly in the E&P segment (€99 million) and in the Chemical business (€61 million). This also included a loss of €101 million recorded on the equity-accounted interest retained in Saipem, which was driven by the recognition of asset impairment charges and other extraordinary expenses by the investee;

(ii)

other net losses mainly relating to an impairment charge recorded in the G&P segment referred to the interest in Unión Fenosa Gas SA (€35 million) due to a reduced profitability outlook.

TABLE OF CONTENTS

2016 compared to 2015. In 2016 the Group reported a net loss from investments of €380 million and mainly related to: (i) results of equity-accounted entities (an overall net loss of €326 million), mainly reported by the Exploration & Production segment due to a weaker commodity scenario and the economic difficulties recorded in certain Countries with a negative impact on the level of inflation and exchange rates. Particularly, the segment incurred a loss of €144 million mainly related to our joint ventures in Venezuela (PetroSucre, which book value was completely written off, Cardón IV and PetroBicentenario) driven by changed economics due to the local currency devaluation and rising inflation leading to escalating operating costs; (ii) a loss of €144 million was recorded on the equity-accounted interest retained in Saipem. This was driven by the recognition of asset impairment charges and other extraordinary expenses accounted for in Saipem's results due to the impairment review performed by the investee at its CGUs based on its updated industrial plan. That plan, announced in October 2016, factored in a slower recovery in the oil market and in investment plans of the international oil companies; (iii) net losses on the divestment of interests (€14 million) mainly relating to the disposal of the residual 2.22% interest in Snam (€32 million), offset by gains on the divestment of interests (€18 million) mainly of the 100% share in Slovenija doo, Eni Hungaria Zrt and other non-core interests; (iv) other losses mainly relating to an impairment charge recorded in G&P related to the interest in Unión Fenosa Gas SA (€84 million) due to a reduced profitability outlook and the impairment of receivables in the E&P segment owed by the equity-accounted PetroSucre SA for dividends resolved but yet to be paid (€65 million). These losses were partly offset by dividends received from entities accounted for at cost (€143 million) relating to Nigeria LNG Ltd (€76 million) and Saudi European Petrochemical Co (€45 million).

These gains are further explained in "Item 18 – note 20 – Investments – of the Notes on Consolidated Financial Statement

g) Taxes

2017 compared to 2016. In 2017, income taxes amounted to €3,467 million, up by €1,531 million compared to 2016, or 79%. This increase reflected higher income before taxes which was up by €5,952 million compared to 2016.

Tax rate was 51% compared to 217% recorded in 2016. This trend was explained by a recovery in profit before taxes of the E&P segment which helped the Company offset against the taxable income a higher share of deductible expenses, including those incurred under PSA contracts, and to dilute the incidence of non-deductible expenses. The reduction also reflected the recognition of deferred taxes in connection with the FID of the Coral project in Mozambique and the production start-up in Ghana.

Taxes included the tax effects relating to operating special items, the write-off of deferred tax asset of subsidiaries in the USA following the recognition of the effect of the newly enacted tax regime (€115 million), offset by the recognition of higher deferred tax asset at Versalis driven by the projection of improving future taxable earnings.

2016 compared to 2015. In 2016, income taxes amounted to €1,936 million, down by €1,186 million compared to 2015, or 38%. These lower charges mainly reflected lower write-downs of deferred tax assets in connection with improved projections of future taxable profit against which those assets would be utilized compared to 2015. Particularly, in 2015 deferred taxes were written down by €1,740 million relating to foreign subsidiaries of the E&P segment and Italian subsidiaries due to a deteriorated profitability outlook. By contrast, the write-downs of deferred tax assets in 2016 were offset by write-ups. In addition, considering the expected outcome of ongoing negotiations to settle disputed receivables owed by the Nigerian national oil company, the Company utilized a provision for deferred tax liabilities for €380 million as those receivables were considered tax-deductible.

In 2015 and in 2016, the Group reported tax rate was much higher than the Group historical tax rates. This negative trend was negatively affected by the increased share of taxable profit earned in PSA contracts which bear higher-than-average rates of tax. Furthermore, in many jurisdictions where the Group reported pre-tax losses, the Company was not in the position of recognizing deferred tax assets, due to lack of sufficient future taxable profit against which those tax assets would be utilized.

Management is estimating that in the four-year plan 2018 – 2021 the Group tax rate will benefit of a growing contribution to the Group pre-tax profit of E&P countries characterized by a lower-than-average tax rate.

Liquidity and capital resources

Eni's cash requirements for working capital, dividends to shareholders, capital expenditures and acquisitions over the past three years were financed primarily by a combination of funds generated from

TABLE OF CONTENTS

operations, borrowings and divestments of minority interests in certain of our exploration assets and other non-strategic activities. The Group continually monitors the balance between cash flow from operating activities and net expenditures targeting a sound and balanced financing structure.

The following table summarizes the Group cash flows and the principal components of Eni's change in cash and cash equivalent for the periods indicated.

	Year ended December 31,		
	2017	2016	2015
	(€ million)		
Net profit (loss) – continuing operations	3,377	(1,044)	(7,399)
Adjustments to reconcile net profit to net cash provided by operating activities:			
- amortization and depreciation charges, impairment losses, write-off and other non monetary items	8,720	7,773	17,216
- net gains on disposal of assets	(3,446)	(48)	(577)
- dividends, interest, taxes and other changes	3,650	2,229	3,215
Changes in working capital related to operations	1,440	2,112	4,781
Dividends received, taxes paid, interest (paid) received during the period	(3,624)	(3,349)	(4,361)
Net cash provided by operating activities – continuing operations	10,117	7,673	12,875
Net cash provided by operating activities – discontinued operations			(1,226)
Net cash provided by operating activities	10,117	7,673	11,649
Capital expenditures – continuing operations	(8,681)	(9,180)	(10,741)
Capital expenditures – discontinued operations			(561)
Capital expenditures	(8,681)	(9,180)	(11,302)
Acquisition of investments and businesses	(510)	(1,164)	(228)
Disposals of consolidated subsidiaries, businesses, tangible and intangible assets and investments	5,455	1,054	2,258
Other cash flow related to investing activities (*) (**)	(32)	5,736	(1,651)
Changes in short and long-term finance debt	(1,712)	(766)	2,126
Dividends paid and changes in non-controlling interests and reserves	(2,883)	(2,885)	(3,477)
Effect of changes in consolidation, exchange differences and cash and cash equivalents related to discontinued operations	(65)	(3)	(780)
Change in cash and cash equivalent for the year	1,689	465	(1,405)
Cash and cash equivalent at the beginning of the year	5,674	5,209	6,614
Cash and cash equivalent at year end	7,363	5,674	5,209

(*)
For 2016, the item also includes the reimbursement of intercompany financing loans owed to Eni by Saipem for € 5,818 million.

(**)
Net cash used in investing activities included investments in and divestments of certain financial assets (mainly bank deposits) to absorb temporary surpluses of cash or as part of our ordinary management of financing activities. Due to

their nature and the circumstance that they are very liquid, these financial assets are netted against finance debt in determining net borrowings. Furthermore, due to the Company's decision to retain a cash reserve composed of held-for-trading securities, net cash used in investing activities also included investments and divestments of those securities. Also these held-for-trading financial assets are netted against finance debt in determining the Group net borrowings. For more information on their composition see Note No. 9 to the Consolidated Financial Statements. For the definition of net borrowings, see "Financial Condition" below. Cash flows of such investing activity were as follows:

(€ million)	2017	2016	2015
Investing activity:			
- securities	(316)	(1,317)	(140)
- financing receivables	(72)	(272)	(343)
	(388)	(1,589)	(483)
Disposal:			
- securities	223		1
- financing receivables	506	6,860	182
	729	6,860	183
Net cash flows used in investing activity	341	5,271	(300)

TABLE OF CONTENTS

The table below sets forth the principal components of Eni's change in net borrowings(1) for the periods indicated.

	Year ended December 31,		
	2017	2016	2015
	(€ million)		
Net cash provided by operating activities	10,117	7,673	11,649
Capital expenditures	(8,681)	(9,180)	(11,302)
Acquisitions of investments and businesses	(510)	(1,164)	(228)
Disposals of consolidated subsidiaries, businesses, tangible and intangible assets and investments	5,455	1,054	2,258
Other cash flow related to capital expenditures, investments and divestments	(373)	465	(1,351)
Net borrowings(1) of divested companies	261	5,848	83
Exchange differences on net borrowings and other changes	474	284	(818)
Dividends paid and changes in minority interest and reserves	(2,883)	(2,885)	(3,477)
Change in net borrowings(1)	3,860	2,095	(3,186)
Net borrowings(1) at the beginning of the year	14,776	16,871	13,685
Net borrowings(1) at year end	10,916	14,776	16,871

(1)
Net borrowings is a non-GAAP financial measure. For a discussion of the usefulness of net borrowings and its reconciliation with the most directly comparable GAAP financial measures see "Financial Condition" below.

Analysis of certain components of Eni's change in net borrowings

In 2017, adjustments to reconcile net profit to net cash provided by operating activities mainly related to non-monetary charges and gains, which primarily regarded depreciation, depletion, amortization, impairment charges and reversals and the write-off of tangible and intangible assets (€7,521 million) and gains on disposals (€3,446 million). Adjustments to net profit also included accrued income taxes (€3,467 million) and interest expense (€671 million), which were more than offset by amounts actually paid (€3,437 million and €582 million, respectively). Net profit was negatively impacted by extraordinary credit losses amounting to €616 million which included the recognition of a valuation allowance for doubtful accounts in the E&P business and in the retail G&P business. Taxes paid included an extraordinary payment made for a tax settlement in Angola (€150 million) relating to past reporting periods.

In 2016, adjustments to reconcile net profit from continuing operations to net cash provided by operating activities from continuing operations mainly related to non-monetary charges and gains, which primarily regarded depreciation, depletion, amortization, impairment charges and reversals and the write-off of tangible and intangible assets (€7,434 million). Adjustments to net profit also included accrued income taxes (€1,936 million) and interest expense (€645 million), which were more than offset by amounts actually paid (€2,941 million and €780 million, respectively).

a) Changes in working capital related to operations

In 2017, working capital generated an inflow of €1,440 million. This was mainly due to a positive balance between trade receivables collected and trade payables paid (a net inflow of €941 million) which reflected the higher volume of trade receivables due subsequently to the reporting date which were sold to financing institutions compared to the previous reporting period (about €282 million) and also the adjustment in connection with the allowance for doubtful accounts in the retail Gas & Power segment.

Finally, other positive working capital adjustments related risk provisions and a positive adjustment relating the item other current assets and liabilities (up by €749 million) which mainly reflected the impairment of receivables in the E&P segment and a change in the derivatives fair value.

In 2016, working capital generated an inflow of €2,112 million. This was mainly due to a positive balance between trade receivables collected and trade payables paid (a net inflow of €2,781 million) which reflected the higher volume of trade receivables due subsequently to the reporting date which were sold to financing institutions compared to the previous reporting period (about €1 billion). This inflow was partly offset by utilizations of the risk provision for €1,043 million, part of which related to the settlement of

118

TABLE OF CONTENTS

obligations towards third parties mainly in the G&P segment also in relation to the final award of an arbitration procedure involving a long-term gas buyer. Conversely an advance made to the same buyer in the previous reporting period was utilized. Finally the working capital inflow was partly absorbed by a reimbursement in-kind of a financing receivable due by an equity-accounted entity operating a gas field in Venezuela with trading receivables (€300 million) due by the Venezuelan state-owned oil company (PDVSA). Finally a positive adjustment related the item other current assets and liabilities (up by €647 million) which mainly reflected the impairment of receivables owed by National Oil Companies due to the expected outcome of ongoing negotiations to settle disputed amounts. The G&P segment was the main driver of the cash inflow from working capital in 2016, reflecting also non-recurring trends. We expect that the G&P working capital contribution will normalize going forward.

b) Investing activities

	Year ended December 31,		
	2017	2016	2015
	(€ million)		
Exploration & Production	7,739	8,254	9,980
Gas & Power	142	120	154
Refining & Marketing and Chemicals	729	664	628
Corporate and other activities	87	55	64
Impact of unrealized intragroup profit elimination	(16)	87	(85)
Capital expenditures – continuing operations	8,681	9,180	10,741
Capital expenditures – discontinued operations			561
Capital expenditures	8,681	9,180	11,302
Acquisitions of investments and businesses	510	1,164	228
	9,191	10,344	11,530
Disposals of consolidated subsidiaries, businesses, tangible and intangible assets and investments	(5,455)	(1,054)	(2,258)

Capital expenditures totaled €8,681 million and €9,180 million, respectively in 2017 and in 2016.

For a discussion of capital expenditures by business segment and a description of year-on-year changes see below "Capital expenditures by segment".

Acquisition of investments and businesses totaled €510 million in 2017 and €1,164 million in 2016. In 2017, acquisition of investments mainly related to the subscription of a share capital increase at equity-accounted entities engaged in the development of Eni's projects, in detail: (i) the Coral FLNG SA (€443 million) which is engaged in the development of a floating production and storage unit of LNG in natural gas-rich Area 4 offshore Mozambique; and (ii) Lotte Versalis Elastomers Co Ltd (€45 million) which is engaged in the production of premium elastomers in South Korea.

In 2016, they comprised the subscription of the share capital increase of Saipem (€1,069 million) and minor contribution to equity-accounted entities.

In 2017, disposals amounted to €5,455 million and mainly related to: (i) the sale to ExxonMobil of a 25% interest in natural gas-rich Area 4 offshore Mozambique where development activities are ongoing to put into production the significant gas resources discovered by Eni. The net cash consideration amounted to €2,061 million including the corresponding portion of net borrowings of the business divested to the buyer amounting to €264 million; (ii) the sale of a 40% stake in the Zohr project located in Egypt sold to BP and Rosneft (€2,526 million); (iii) the sale of the whole interest in the consolidated company Eni Gas & Power NV and its subsidiary Eni Wind Belgium NV, operating in the gas & power retail activities in Belgium. The sale price amounted to €302 million including cash divested of €8 million.

In 2016, disposals amounted to €1,054 million and mainly related to: (i) the divestment of the 12.503% interest in Saipem SpA to CDP Equity SpA in January 2016 (€463 million), an interest in Snam due to exercise of the conversion right by bondholders (€332 million) as well as fuel distribution activities in Eastern Europe.

In 2016, other cash flow related to investing activities were positive for €465 million and included the reimbursement in-kind of a financing receivable owed by our equity-accounted entity Cardón IV for €300

119

TABLE OF CONTENTS

million. Cardón IV reimbursed Eni with a trade receivable due by the Venezuelan State-owned oil company (PDVSA) on the supplies of gas volume produced at the Perla project. Furthermore, the production restart of the Kashagan field and the achievement of a production milestone in the fourth quarter of 2016 triggered the reimbursement of the first instalment of a receivable of the divestment of an interest of 1.71% of the project to the Kazakh national oil company occurred in 2008, with a cash-in of €152 million. A second instalment was reimbursed in 2017.

c) Dividends paid and changes in non-controlling interests and reserves

In 2017, dividends paid and changes in non-controlling interests and reserves (€2,883 million) related almost exclusively to cash dividends to Eni shareholders (€2,880 million, of which €1,440 million relating to the 2017 interim dividend and €1,440 million to the final dividend for fiscal year 2016).

In 2016, dividends paid and changes in non-controlling interests and reserves (€2,885 million) related almost exclusively to cash dividends to Eni shareholders (€2,881 million, of which €1,441 million relating to the 2016 interim dividend and €1,440 million to the final dividend for fiscal year 2015.

Financial condition

Management assesses the Group's capital structure and capital condition by tracking net borrowings, which is a non-GAAP financial measure. Eni calculates net borrowings as total finance debt (short-term and long-term debt) derived from its Consolidated Financial Statements prepared in accordance with IFRS less: cash, cash equivalents and certain highly liquid investments not related to operations including, among others, a liquidity reserve made of held-for-trading securities and finally other liquid assets not related to operations (financing receivables and securities). The Company is retaining a liquidity reserve, which comprises very liquid investments, mainly sovereign and corporate securities which management has selected based on their creditworthiness. This cash reserve was established by investing part of the proceeds from the disposal plan carried out in the latest years.

Those securities amounted to €6,219 million as of end of 2017 and were accounted as mark-to-market financial instruments. For further information see "Item 18 – note 9 – Financial assets held for trading – of the Notes on Consolidat Financial Statements". Non-operating financing receivables consist mainly of deposits with banks and other financing institutions and deposits in escrow.

Management believes that net borrowings is a useful measure of Eni's financial condition as it provides insight about the soundness of Eni's capital structure and the ways in which Eni's operating assets are financed. In addition, management utilizes the ratio of net borrowings to total shareholders' equity including non-controlling interest (leverage) to assess Eni's capital structure, to analyze whether the ratio between finance debt and shareholders' equity is well balanced compared to industry standards and to track management's short-term and medium-term targets. Management continuously monitors trends in net borrowings and trends in leverage in order to optimize the use of internally-generated funds versus funds from third parties. The measure calculated in accordance with IFRS that is most directly comparable to net borrowings is total debt (short-term and long-term debt). The most directly comparable measure, derived from IFRS reported amounts, to leverage is the ratio of total debt to shareholders' equity (including non-controlling interest). Eni's presentation and calculation of net borrowings and leverage may not be comparable to other companies.

TABLE OF CONTENTS

The tables below set forth the calculations of net borrowings and leverage for the periods indicated and their reconciliation to the most directly comparable GAAP measure.

	As of December 31,					
	2017			2016		
	Short-term	Long-term	Total	Short-term	Long-term	Total
	(€ million)					
Finance debt (short-term and long-term debt)	4,528	20,179	24,707	6,675	20,564	27,239
Cash and cash equivalents	(7,363)		(7,363)	(5,674)		(5,674)
Securities held for trading and other securities held for non operating purposes	(6,219)		(6,219)	(6,404)		(6,404)
Non operating financing receivables	(209)		(209)	(385)		(385)
Net borrowings	(9,263)	20,179	10,916	(5,788)	20,564	14,776

		As of December 31,	
		2017	2016
Shareholders' equity including non-controlling interest as per Eni's Consolidated Financial Statements prepared in accordance with IFRS	(€ million)	48,079	53,086
Ratio of finance debt to total shareholders' equity including non-controlling interest		0.51	0.51
Less: ratio of cash, cash equivalents and certain liquid investments not related to operations to total shareholders' equity including non-controlling interest		(0.29)	(0.23)
Ratio of net borrowing to total shareholders' equity including non-controlling interest (leverage)		0.23	0.28

In 2017, net borrowings amounted to €10,916 million, representing a €3,860 million decrease from 2016. This reduction was driven by net cash flow from operations amounting to €10,117 million and the finalization of portfolio transactions as part of the Dual Exploration Model (the disposal of a 40% interest in Zohr in Egypt and of a 25% interest in Area 4 offshore Mozambique) and other non-strategic assets (retail activity in Belgium). Income taxes on the disposals of Eni's interests in Zohr and in Area 4 in Mozambique (€0.44 billion) were netted against cash flow from disposals, as provided by international accounting standards. Cash flow from operations was also influenced by a higher level of receivables due beyond the end of the reporting period being sold to financing institutions compared to the amount sold at the end of the previous reporting period (approximately €0.3 billion).

The ratio of finance debt to total equity was 0.51 at 2017 year-end.

The Group Non-GAAP measure of its financial condition "Leverage" was 0.23 at December 31, 2017 reporting a decrease from 0.28 as of the end of 2016. This decline was driven by lower net borrowing, the effects of which were partly offset by a reduction in the Group total equity as explained below.

Total equity decreased by €5,007 million from December 31, 2016. This was due to the negative foreign currency translation differences (€5,573 million) due to a 13.9% appreciation of the euro against the US dollar at year end (the exchange rate recorded on December 31, 2017 at 1.202, compared to 1 euro = 1.055 euro US$ at December 31, 2016), as well as dividend distribution of €2,880 million. These negatives were partly offset by profit for the year.

Total debt of €24,707 million consisted of €4,528 million of short-term debt (including the portion of long-term debt due within twelve months equal to €2,286 million) and €20,179 million of long-term debt.

Total debt included unsecured bonds for €17,965 million (including accrued interest and discount on issuance). Bonds maturing in the next 18 months amounted to €2,199 million (including accrued interest and discount). Bonds issued in

2017 amounted to €1,817 million (including accrued interest and discount). Total debt was denominated in the following currencies: euro (89%), U.S. dollar (8%), British pound (2%) and 1% in other currencies.

TABLE OF CONTENTS

Capital expenditures by segment

Exploration & Production. In 2017, capital expenditures of the Exploration & Production segment amounted to €7,739 million, mainly related to the development of oil&gas reserves (€7,236 million). Significant expenditures were directed mainly outside Italy, in particular in Egypt, Ghana, Angola, Congo, Algeria, Iraq and Norway. Exploration expenditures (€442 million) were directed in particular in Cyprus, Norway, Mexico, Egypt, Libya and Ivory Coast.

In 2016, capital expenditures of the Exploration & Production segment amounted to €8,254 million, mainly related to the development of oil&gas reserves (€7,770 million). Significant expenditures were directed mainly outside Italy, in particular in Egypt, Angola, Kazakhstan, Indonesia, Iraq, Ghana and Norway. Development expenditures in Italy also comprised the upgrading of certain plants at the Viggiano oil center in Val d'Agri, which did not alter the plant set up. This upgrading addressed certain objections made by jurisdictional Authorities about the proper function of the plants and were duly authorized by the competent department of the Italian Ministry of Economic Development. Due to this upgrading, plant activities were regularly restarted following notification by the public prosecutor that it has definitively repealed the plant seizure, as well as sidetrack and workover activities in mature fields. Exploration expenditures (€417 million) were directed in particular in Egypt, Indonesia, Libya and Angola.

Gas & Power. In 2017, capital expenditures in the Gas & Power segment totaled €142 million and mainly related to gas marketing initiatives (€102 million) and to the flexibility and upgrading initiatives of combined cycle power plants (€36 million).

In 2016, capital expenditures in the Gas & Power segment totaled €120 million and mainly related to initiatives to improve flexibility of the combined-cycle power plants (€41 million) and to develop the gas marketing activity (€69 million).

Refining & Marketing and Chemicals. In 2017, capital expenditures in the Refining & Marketing and Chemicals segment amounted to €729 million and regarded mainly: (i) refining activity in Italy and outside Italy (€395 million) aiming fundamentally at reconstruction works of the EST conversion plant at the Sannazzaro refinery, maintain plants' integrity, reconversion of refinery system, as well as initiatives in the field of health, security and environment; (ii) marketing activity, mainly regulation compliance and stay in business initiatives in the refined product retail network in Italy and in the Rest of Europe (€131 million); (iii) upgrading activities (€84 million); upkeeping of plants (€42 million); maintenance (€42 million), as well as environmental protection, safety and environmental regulation (€35 million) in the Chemicals segment (€203 million).

In 2016, capital expenditures in the Refining & Marketing and Chemicals segment amounted to €664 million and regarded mainly: (i) refining activities in Italy and outside Italy (€298 million) aiming fundamentally at plants improving, as well as initiatives in the field of health, security and environment; (ii) marketing activity, mainly regulation compliance and stay in business initiatives in the refined product retail network in Italy and in the Rest of Europe (€123 million); (ii) upgrading and maintenance at petrochemical plants (€200 million).

TABLE OF CONTENTS

Recent developments

The table below sets forth certain indicators of the trading environment for the periods indicated:

	Three months ended December 31 2017	Three months ended March 31, 2017	Three months ended March 31, 2018
Average price of Brent dated crude oil in U.S. dollars(1)	61.39	53.78	66.82
Average EUR/USD exchange rate(2)	1.177	1.065	1.229
Standard Eni Refining Margin (SERM)(3)	4.3	4.2	3.0

(1)
Price per barrel. Source: Platt's Oilgram.

(2)
Source: ECB.

(3)
In $/BBL, FOB Mediterranean Brent dated crude oil. Source: Eni calculations. Approximates the margin of Eni's refining system in consideration of material balances and refineries' product yields.

In the period January 1 – March 31, 2018 the Brent crude oil price was 66.82 $/BBL on average, 24.2% higher than in the first quarter of 2017. This trend will positively affect reported revenues, profitability and cash flow of our Exploration & Production segment, partly offset by the depreciation of the USD.

Significant transactions

In March 2018, Eni agreed to sell to Mubadala Petroleum a 10% stake in the Shorouk concession, offshore Egypt, where the Zohr gas field is currently producing. The agreed consideration is $934 million. The completion of the transaction is subject to the fulfillment of certain standard conditions, including all necessary authorizations from Egypt's Authorities.

In March 2018, Eni signed in Abu Dhabi two Concession Agreements for the acquisition of a 5% stake in the Lower Zakum offshore oil field and of a 10% stake in the oil, condensate and gas offshore fields of Umm Shaif and Nasr, for a total participation fee of about $875 million and a contractual term of 40 years.

The Company's Annual General Shareholders Meeting scheduled on May 10, 2018, has been convened to approve the full year dividend proposal of €0.80 per share of which €0.40 paid as interim dividend in September 2017. Eni expects to pay the balance of the dividend for fiscal year 2017 amounting to €0.40 per share in May 2018. The total cash out is estimated at approximately €1.4 billion.

Management's expectations of operations

Exploration & Production

Management intends to boost the cash generation in the E&P segment leveraging on profitable production growth, capital discipline, effective project execution and strict control of operating expenses and working capital.

Exploration will continue driving the Company's growth in the short and long-term. In the next four years, our exploration activities will focus on supporting the replacement of produced reserves and on contributing to cash generation. Our priorities in exploration will be:

i)
The discovery of reserves near-field and in proximity to fields under development, where we can leverage on existing infrastructures in order to readily put into production the discovered resources, ensuring fast contribution to cash flows;

ii)
Initiatives in operated licenses with high working interests targeting conventional resources, where in case of material discoveries we can apply our dual exploration model;

iii)
A resumption of activities in high-risk, high-rewards plays.

TABLE OF CONTENTS

Our dual exploration model contemplates both the rapid development of the discovered resources and the divestment of stakes of our exploration discoveries in order to accelerate the conversion of our resources into cash, as witnessed by the closing in 2017 of the deals relating to the divestiture of a 40% interest in the Zohr gas field in Egypt and of a 25% of gas-rich Area 4 offshore Mozambique.

We expect to increase our hydrocarbons production at an average rate of 3.5% across the 2018 – 2021 plan period. This grow will be fuelled organically by new fields start-ups, full production at the fields started in 2017, particularly the Zohr gas field, and continuing production optimization to fight fields natural decline. The main start-ups across the plan period include the gas phase of the Offshore Cape Three Points project in Ghana, development of satellites fields in the Block 15/06 off Angola, the production start-up at Area 1 offshore Mexico and at the Merakes field in Indonesia, additional ramp-ups of the Great Nooros Area fields in Egypt and the high-grading of the Karachaganak field and upgrading of our main fields in Libya. New field start-ups and production ramp-ups will add approximately 700 KBOE/d in 2021. Production optimizations will add 200 KBOE/d in 2021. We believe that those production targets have good visibility because they related to already-sanctioned projects, most of which are operated by Eni, and to incremental development phases at our existing profit centers.

Oil price assumptions are particularly significant when it comes to assessing the Company's future production performance considering the entitlement mechanism under Eni's PSAs and similar contractual schemes. The Company estimates that production entitlements in its current portfolio of PSAs vary on average by approximately 2,000 BBL/d for each $1 change in oil prices compared to current Eni's assumptions for oil prices. We note that in case oil prices differ significantly from our own forecasts, the result of the above mentioned sensitivity of production to oil price changes may be significantly different.

To factor in possible risks of unfavorable geopolitical developments in our countries of operations, which may lead to temporary production losses and disruptions in connection with, among others, acts of war, sabotage, social unrest, clashes and other form of civil disorder, we have applied a haircut to our future production levels based on management's appreciation of those risks, past experience and other considerations. However, this contingency factor does not cover worst-case developments and extreme events, which could determine prolonged production shutdowns. It is worth mentioning that we expect to reduce our exposure to Libya over the plan period as a result of the slowdown in our exploration and development activities in recent years due to an uncertain political outlook.

Our production plans are incorporating our Brent price scenario of 60 $/BBL in 2018 and a gradual increase in the subsequent years up to our long-term case of 72 $/BBL in 2021 and going forwards (on constant monetary term compared to 2021, i.e. from 2021 onwards crude oil prices will grow in line with a projected inflationary rate). See "Item 4 – Exploration & Production". Our pricing assumptions are based on the progressive rebalancing of global oil markets, which in our view will be supported in the short-term by the agreement between Opec members and other producing countries to curb production, effective until the end of 2018, and going forward by (i) the effects of the curtailment in expenditures made by international oil companies during the downturn which could led to supply shortage and (ii) a strengthening macroeconomic outlook. However, there are some risks to this outlook, including the role of OPEC and its ability to control global prices and the pace at which unconventional oil producers in the US will be able to bring production back to markets, leveraging the short-cycle nature of this business and rising productivity. We note that the pace of recovery in crude oil prices has slowed down in February and in March and that forward curves of crude oil prices remains in backwardation for long-dated maturities.

Due to those risks and uncertainties, management intends to retain a strong focus on capital and cost discipline and on reducing the time-to-market of our reserves. First, our capital projects will be carefully selected against our scenario assumptions and minimum requirements of internal rates of return. We intend to reduce financial exposure leveraging on a phased approach in developing our projects and on monitoring idle capital employed. Secondly, we plan to continue our focus on delivering our planned projects on time and on budget. Several of our projects are complex due to scale and reach of operations, environmentally-sensitive locations, external conditions, including offshore operations, industry limits and other considerations including the risk factors described in Item 3. These constraints and factors might cause delays and cost overruns. We plan to mitigate those risks in the future by continuing deployment of our skills and by our model of project execution driven by: (i) parallel execution of the main project activities, including discovery appraisal and pre-fid activities; (ii) the in-sourcing of critical engineering and project management phases, for example we are directly managing hook-up and commissioning; (iii) the

TABLE OF CONTENTS

design-to-cost method whereby the Company has redirected its exploration efforts towards mature and low-complexity areas where we can achieve fast time-to-market and cost synergies. Furthermore, phased project development and strict integration between exploration and development have improved the overall project execution and cost efficiency. Finally, we plan to seek opportunities for further reductions in our development and operating costs, for example by reducing the downtime at our facilities and other measures. The mentioned drivers will underpin the profitability of our production going forward, despite our projections of rising trends in the supply costs of materials and equipment in the range of a few percentage points. Due to those drivers and our estimation that in recent years our discovery costs have been efficient, we believe that the price breakeven of our ongoing projects under execution has decreased over the latest years.

Management also plans to increase the share of operated production in the Company's portfolio. We expect to operate more than 74% of the plan period production. Project operatorship enables the Company to better schedule and control project execution, expenditures and timely achievement of project milestones and to mitigate project risks.

Gas & Power

We expect a weak outlook in the Gas & Power segment due to structural headwinds in the industry as we forecast sluggish demand growth, oversupplies and strong competition across all of our main markets in Europe, including Italy. In spite of a better macroeconomic environment, demand growth will be dampened by rising competition from renewables and increasing energy efficiency. Rising global supplies of LNG will drive continuing competition and pricing pressure. LNG supplies will be fueled by the coming on stream of several export terminals in the United States which will monetize the country's large reserves of shale gas and the start-up of large LNG projects in the Pacific area. Finally, a new, large project to export gas via pipeline to Europe is expected to start operations in 2020, which will link the Italian market to gas fields in Azerbaijan, and possible regulatory developments might increase the liquidity of the Italian spot market by granting access to gas infrastructures (namely, Italian LNG re-gasification terminals and transport capacity at the main European backbones conveying gas from Northern Europe to Italy) to new comers. These trends are expected to be exacerbated by the constraints of the long-term supply contracts with take-or-pay clauses, which will trigger pricing competition among wholesale operators to limit the financial exposure arising from the contracts in case of volumes off-taken below the minimum take. Based on those expectations, there are market risks to the differential between spot prices at Italian hubs and at European hubs, which management leverages to recover the fixed expenses in the gas wholesale business.

Against this scenario, the Company priority in its Gas & Power business is to strengthen profitability and cash generation. The main drivers to achieve these goals will be the renegotiations of our long-term gas supply contracts to align pricing and volume terms to current market conditions and dynamics, by achieving consistency between supply costs and selling prices on the main markets, considering expectations for an alignment of spot prices at the Italian hubs to those of continental hubs and the fact that our long – term contracts are mainly indexed to spot prices at continental hubs, and minimum off-takes in line with end-markets demand. We plan to optimize our logistic costs, by leveraging on asset-backed activities and eventually on possible regulatory developments intended to increase markets liquidity. We expect better results in our LNG, trading and retail businesses. In LNG, we will leverage on the integration with our upstream operations to extract more value from the development of our gas reserves. We are planning for the achievement of 12 million tonnes per year of contracted volumes in 2021, of which 8 million will come from our equity production in Africa and Far East. In this way, we will seek to capture market opportunities through the flexibilities of our upstream portfolio. In the Gas & Power retail business, the Company's marketing effort will address retail customers in Italy and in the European markets where we operate in order to valorize the existing customer base against the backdrop of escalating competitive pressures. This will be achieved by the offer of new products and services, brand identity, the administrative advantages of the dual offer of gas and electricity, a competitive cost to serve and continuing innovation in processes, promotion and customer care and post-sale assistance also leveraging on the deployment of digitalization.

Finally, the Company intends to capture margins improvements by means of trading activities by entering into derivative contracts both in the commodity and the financial trading venues in order to capture possible favorable trends in market prices, within the limits set by internal policies and guidelines that define the maximum tolerable level of market risk. As part of this strategy, the Company intends to

TABLE OF CONTENTS

improve results of operations by effectively managing the flexibilities associated with the Company's assets (gas supply contracts, transportation rights, storage capacities, unutilized power capacity). This can be achieved through strategies of asset-backed trading by entering into derivative contracts to leverage on commodity price volatility, the risks of which might be absorbed in part or entirely by the natural hedge granted by the asset availability.

Asset-backed activities may lead to gains, as well as losses the amount of which could be significant. For further information on the market risk and how the Company manages it see "Item 11 – Quantitative and Qualitative Disclosures about Market Risk".

Based on the above outlined trends and industrial actions, management expects that we will retain profitable, cash-positive operations in the Company's gas marketing business over the plan period. Our profitability outlook factors in the expected benefits of the ongoing renegotiations of the Company long-term supply contracts, which the Company is seeking to finalize during the plan period, as well as other circumstances subject to risks and uncertainties described in Item 3.

Refining & Marketing

The outlook of the European refining sector is challenging due to structural headwinds in the industry pressured by overcapacity and rising competition from cheaper products streams from the Middle East and other areas, as fuel demand is projected to recover moderately. Management expects refining margins to hover around the 5 $/BBL level in the next four years and beyond. Currently, our refining business breaks even at around 4 $/BBL. A further appreciation of the euro vs. the dollar could negatively affect this target.

Against this backdrop, the Company priority is to retain profitable and cash-positive operations even in a depressed downstream oil environment, by further reducing the breakeven margin of Eni refineries, targeting 3 $/BBL by the end of 2018. The planned initiatives to achieve this goal include the completion of the Gela project designed to transform this refinery into a green refinery, i.e. a refinery able to process renewable feedstock, the second phase of the Venice refinery upgrading, optimization of plant setup and feedstock supply, improved conversion capacity and continued efficiency gains in logistics, energy management and capital discipline. The rebuilding of the EST conversion unit at the Sannazzaro Refinery will be another driver to achieve the target break-even margin. In Marketing activities, where we expect competitive pressure to continue due to muted demand trends, we are planning to improve results of operations mainly by focusing on innovation of products and services anticipating customer needs, strengthening our line of premium products, as well as efficiency in the marketing and distribution activities. Further value will be extracted by the development of our initiatives in the segment of sustainable mobility. Finally, operation efficiency will be supported by our planned deployment of digitalization technologies. We believe that this action will support the achievement of profitable and cash-positive operations at our scenario assumptions.

Chemical

The outlook in the Chemical business is supported by an improving macroeconomic outlook, tempered by structural headwinds in the industry pressured by overcapacity and rising competition from cheaper products streams from the Middle East, Far East and the US. In addition, our petrochemical commodities are exposed to the volatility of the crude oil-based feedstock costs. Over the last few years, we have restructured our business by reducing capacity at low-margin products, divesting or exiting unprofitable lines, plant optimization and other efficiency measures as well as a shift in our product portfolio towards specialties, green chemicals and products with high technology content, which are less exposed to the scenario volatility. Looking forward we believe that further steps are needed to preserve profitable and cash-positive operations. The industrial plan identified the following lines of action: strengthening the productive footprint by means of improved asset integration, increasing efficiency and reliability as well as plant utilization rates; upgrading the product mix by developing differentiated products, green products and new applications through internal R&D and the acquisition of new technologies; and expanding internationally leveraging on joint-venture projects targeting markets with growth opportunities and access to competitive feedstock and outlets. We believe that this action will support the achievement of profitable and cash-positive operations at our scenario assumptions.

Capital expenditures plan

Over the next four years, the Company plans to invest something below €32 billion, unchanged from the previous plan, to support continued organic growth in oil&gas production; approximately 80% of

TABLE OF CONTENTS
planned capital expenditures will be directed to the Exploration & Production segment. The remaining part will fund our ongoing expansion program in the green businesses and selective growth opportunities in the R&M and Chemical segment. Eni's capital expenditures program is reflective of uncertainties about future trends in the oil markets. We intend to retain strict financial discipline going forward by focusing on the more profitable projects in portfolio and project re-phasing and modularization to reduce our financial exposure. In 2018 we expect to make capital expenditures of approximately €7.7 billion assuming an exchange rate of 1.17 €/$.

Development of oil&gas reserves will attract some €24 billion, of which approximately €16 billion directed to new field start-ups and ramp-ups, while the remaining to production optimization. Project start-ups and plateau enhancement at existing fields will be geographically diversified and executed mainly in Egypt, with the ramp-up of the very important Zohr gas field, Norway, Libya, Nigeria, Kazakhstan and Indonesia, while development activities will continue in Mozambique. Egypt will attract approximately 20% of the Group development expenditures over the plan period. By the end of 2018, we expect to make six main FIDs that, together with our ongoing projects, will entirely cover our production growth up to 2021.

Exploration capex will amount to €2 billion. Our projects will comprise near-field activities designed to provide fast production support and contribution to the cash flow, as well as new initiatives targeting conventional prospects with high working interest in order to support Eni's dual exploration model in case of material discoveries. Finally, we forecast selective initiatives in high-risk, high-reward plays.

We are planning to invest approximately €3.5 billion in R&M and Chemical. In R&M our main capital projects include completion of the Gela reconfiguration project, the rebuilding of the EST unit at the Sannazzaro refinery and various initiatives of plant upgrading, as well as network upgrading. In the Chemical business the planned initiatives include plant upgrading and selected growth projects. Finally, we will invest approximately more than €1.8 billion in the green business, the bulk of which will be directed to develop photovoltaic and other renewable-related power plants at our industrial hubs in Italy, or as part of selected E&P properties outside Italy, targeting an installed production capacity of 1 gigawatt at the end of the plan period.

Management expects to pursue strict capital discipline when assessing individual capital projects. Management is assuming a long-term oil price of 72 $/BBL for the Brent benchmark, which is adjusted to take account of expected inflation rates from 2022 onwards. The internal rate of return of each project is compared to the relevant hurdle rate, differentiated by business segment and country of operation. These hurdle rates are calculated taking into account: (i) the weighted average cost of capital ("WACC") to the Group. In 2017, management assessed that the cost of capital to the Group increased marginally from 2016 mainly due to higher yields on risk-free assets reflecting an improved macroeconomic outlook. Furthermore, we recorded an appreciation of the country risk, which factors in the perceived level of risk associated with our countries of operations in terms of current trends and conditions in the macroeconomic, business, regulatory and socio-political framework, as well as the consensus outlook. A country risk premium is added to the Group WACC and a premium for the business risk in determining the hurdle rates, which are utilized by management in its final investment decisions.

Liquidity and leverage

Considering the uncertainties about future trends in market fundamentals and price volatility, management's priorities remain to maximize the Group's cash generation and to preserve a solid balance sheet. We believe the initiatives implemented by management during the downturn intended to lower the cost base, to select capital expenditures and to streamline operations together with the monetization of part of our recent exploration discoveries have improved the Company's competitive position and strengthened its capital structure. In future years we will continue to focus on financial discipline, which means project selection and cost control, and sustainable growth which will drive profitable production increases, reserve replacement, margin expansion and improving results at our mid and downstream businesses. We expect that better business effectiveness and efficiency and improved operations profitability will help reduce the Brent price at which the Company will be able to fund through cash flow from operations both the planned capital expenditures and the dividend. We are estimating that in 2018 our cash neutrality will be at 55 $ / BBL assuming an average €/$ exchange rate of 1.17, and then will progressively decline in the low fifties by end of the plan period. These targets are reflective of the Company's initiatives in lowering its cost base and in optimizing its capital plan without impairing its ability to pursue its growth objectives.

TABLE OF CONTENTS

During the downturn, in spite of the sharp contraction in net cash provided by operating activities due to lower oil prices, the Company has managed to maintain its key ratio of net borrowings to equity – leverage – within the ceiling of 0.3 through a combination of cost cuts, asset disposals, capital expenditures curtailments and working capital optimization. At the end of 2017, our leverage stood at 0.23. Looking ahead, we are lowering the target leverage in a range of 0.2 – 0.25. Management believes that the target range leverage is consistent with the Company's business profile, which features a large exposure to the Exploration & Production segment, and with an uncertain commodity scenario.

Our cash flow projections are exposed to the volatility in the oil price environment and in the USD vs. the EUR exchange rate. Currently, based on our portfolio of oil&gas properties, we estimate that, holding all other factors constant, our net profit and cash flow from operations vary by approximately €0.2 billion for each dollar change in Brent prices on a yearly basis compared to our price forecast. We note that the Brent price in the period January 1 to March 31, 2018 was approximately 66.8 $/BBL on average (it was 54 $/BBL on average in the period January 1 to March 31, 2017). We retain some levels of financial flexibility that we may use in case oil prices should take another leg down in the cycle in the remainder of the year or in subsequent years. Particularly, approximately 50% of the planned investment at the end of the 2018 – 2021 plan has been allocated to projects yet to be sanctioned. In addition, we retain cash reserves and committed and uncommitted borrowing facilities and we are planning to make additional asset disposals in the range of €1.5 billion by 2020 leveraging on our strategy of fast monetizing our high working interests in recent hydrocarbons discoveries.

For planning purposes, management assumed a EUR/USD exchange rate in the range of 1.17 – 1.25 U.S. dollars per euro in the 2018 – 2021 period. Given the sensitivity of Eni's results of operations to movements in the euro versus the U.S. dollar exchange rate, trends in the currency market represent a factor of risk and uncertainty. Currently, we are estimating that our cash flow from operations minus cash flow from investing/divesting activities varies by approximately €0.2 billion for each 5 cent USD/EUR change. We note that in the period January 1 to March 31, 2018 the EUR/USD exchange rate was approximately 1.23 and appreciated year-on-year. This trend is expected to negatively affect the reported amount of revenues, operating profit and cash flow in our E&P segment. See "Item 3 – Risk factors".

Dividend policy

Management is committed to a progressive distribution policy in line with our plans of underlying earnings and cash flow growth and considering the scenario evolution. Dividend growth will be driven by the results that ultimately will be achieved in implementing our strategy and by our ability to reduce the expected Brent prices at which the Company's cash flows from operating activities are able to fund planned capital expenditures and dividend payments. Considering the Company's outlook of improving results and better business performance and the progress achieved so far in delivering on our financial and industrial targets, management is forecasting to increase the 2018 dividend to €0.83 per share compared to €0.80 per share for fiscal year 2017. Furthermore, the Company is exploring a resumption of the share repurchase program, which management views as a flexible tool to return shareholders cash in excess of that committed to achieve the targeted range of leverage.

In future years, management expects to continue paying interim dividends for each fiscal year, with the balance for the full-year dividend paid in the following year.

The expectations described above are subject to risks, uncertainties and assumptions associated with the oil&gas industry, and economic, monetary and political developments in Italy and globally that are difficult to predict. There are a number of factors that could cause actual results and developments to differ materially, including, but not limited to, political instability in Libya and other countries, crude oil and natural gas prices; demand for oil&gas in Italy and other markets; developments in electricity generation; price fluctuations; drilling and production results; refining margins and marketing margins; currency exchange rates; general economic conditions; political and economic policies and climates in countries and regions where Eni operates; regulatory developments; the risk of doing business in developing countries; governmental approvals; global political events and actions, including war, terrorism and sanctions; project delays; material differences from reserves estimates; inability to find and develop reserves; technological development; technical difficulties; market competition; the actions of field partners, including the inability of joint venture partners to fund their share of operating or developments activities; industrial actions by workers; environmental risks, including adverse weather and natural disasters; and other changes to business conditions. Please refer to “Item 3 – Risk factors”.

TABLE OF CONTENTS

Off-balance sheet arrangements

Eni has entered into certain off-balance sheet arrangements, including guarantees, commitments and risks, as described in "Item 18 – note 38 – Guarantees, commitments and risks – of the Notes on Consolidated Financial Statement Eni's principal contractual obligations, including commitments under take-or-pay or ship-or-pay contracts in the gas business, are described under "Contractual obligations" below. See the Glossary for a definition of take-or-pay or ship-or-pay clauses.

Off-balance sheet arrangements comprise those arrangements that may potentially impact Eni's liquidity, capital resources and results of operations, even though such arrangements are not recorded as liabilities under generally accepted accounting principles. Although off-balance sheet arrangements serve a variety of Eni's business purposes, Eni is not dependent on these arrangements to maintain its liquidity and capital resources; nor is management aware of any circumstances that are reasonably likely to cause the off-balance sheet arrangements to have a material adverse effect on the Company's financial condition, results of operations, liquidity or capital resources.

Eni has provided various forms of guarantees on behalf of unconsolidated subsidiaries and affiliated companies, mainly relating to guarantees for loans, lines of credit and performance under contracts. In addition, Eni has provided guarantees on the behalf of consolidated companies, primarily relating to performance under contracts. These arrangements are described in "Item 18 – note 38 – Guarantees, commitments and risks – of the Notes on Consolidated Financial Statements".

Contractual obligations

The amounts in the table refer to expected payments, undiscounted, by period under existing contractual obligations commitments.

	Total	2018	2019	2020	2021	2022	2023 and thereafter
	(€ million)						
Total debt	25,620	5,253	4,148	2,867	1,280	1,262	10,810
Long-term finance debt	22,276	2,000	4,084	2,857	1,279	1,246	10,810
Short-term finance debt	2,242	2,242					
Fair value of derivative instruments	1,102	1,011	64	10	1	16	
Interest on finance debt	3,513	582	511	411	304	250	1,455
Guarantees to banks	473	473					
Non-cancelable operating lease obligations(1)	4,532	883	525	485	371	329	1,939
Decommissioning liabilities(2)	14,786	348	411	398	375	207	13,047
Environmental liabilities	2,673	317	311	282	228	178	1,357
Purchase obligations(3)	107,830	10,989	9,862	8,223	8,233	8,071	62,452
Natural gas to be purchased in connection with take-or-pay contracts(4)	100,244	8,644	8,708	7,452	7,542	7,553	60,345
Natural gas to be transported in connection with ship-or-pay contracts(4)	4,687	1,272	760	516	468	380	1,291
Other ship-or-pay obligations	589	110	99	87	73	59	161

Other purchase obligations(5)	2,310	963	295	168	150	79	655
Other obligations(6)	128	11	3	2	2	2	108
of which:							
- Memorandum of intent relating to Val d’Agri	128	11	3	2	2	2	108
TOTAL	159,555	18,856	15,771	12,668	10,793	10,299	91,168

(1)
Operating leases primarily regarded FPSO vessels, assets for drilling activities, time charter and long-term rentals of vessels, lands, service stations and office buildings. Such leases did not include renewal options. There are no significant restrictions provided by these operating leases which limit the ability of the Company to pay dividend, use assets or to take on new borrowings.

(2)
Represents the estimated future costs for the decommissioning of oil and natural gas production facilities at the end of the producing lives of fields, well-plugging, abandonment and site restoration.

(3)
Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms.

(4)
Such arrangements include non-cancelable, long-term contractual obligations to secure access to supply and transport of natural gas, which include take-or-pay or ship-or-pay clauses whereby the Company obligations consist of offtaking minimum quantities of product or service or paying the corresponding cash amount that entitles the Company to off-take the product in future years. Future obligations in connection with these contracts were calculated by applying the forecasted prices of energy or services included in the four-year business plan approved by the Company’s Board of Directors and on the basis of the long-term market scenarios used by Eni for planning purposes to minimum take and minimum ship quantities. See “Item 4 – Gas & Power – Natural Gas Purchases” and “Item 3 – Risk Factors – Risks in the G&P business.

(5)
Mainly refers to arrangements to purchase capacity entitlements at certain re-gasification facilities in the United States of euro 948 million.

(6)
In addition to these amounts, Eni has certain obligations that are not contractually fixed as to timing and amount, including contributions to defined benefit pension plans (See Note 31 to the Consolidated Financial Statements).

TABLE OF CONTENTS

The table below summarizes Eni's capital expenditures commitments for property, plant and equipment as of December 31, 2017. Capital expenditures are considered to be committed when the project has received the appropriate level of internal management approval. Such costs are included in the amounts shown below.

	Total	2018	2019	2020	2021	2022 and subsequent years
	(€ million)					
Committed projects	23,859	6,309	5,688	4,717	3,375	3,770

Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the Group may not be available, or the Group is unable to sell its assets on the marketplace as to be unable to meet short-term finance requirements and to settle obligations. Such a situation would negatively impact Group results as it would result in the Company incurring higher borrowing expenses to meet its obligations or under the worst of conditions the inability of the Company to continue as a going concern. At present, the Group believes it has access to sufficient funding and has also both committed and uncommitted borrowing facilities to meet currently foreseeable borrowing requirements. The Group has also established a cash reserve, which consists of cash on hand and very liquid financial assets (short-term deposits and held-for-trading securities). This cash reserve according to management plans can alternatively be used to absorb temporary swings in cash flows from operations, to provide financial flexibility to pursue the Group development programs or to fund the Group contractual obligations with respect to the repayment of financing debt at maturity over a 24-month horizon. For a description of how the Company manages the liquidity risk see "Item 18 – note 38 of the Notes on Consolidated Financial Statements".

Working capital

Management believes that, taking into account unutilized credit facilities, the Company's liquidity reserves, our credit rating and access to capital markets, Eni has sufficient working capital for its foreseeable requirements.

Credit risk

Credit risk is the potential exposure of the Group to losses in case counterparties fail to perform or pay amount due.
For a description of how the Company manages the credit risk see "Item 18 – note 38 of the Notes on Consolidated Financial Statements".
For information about credit losses in 2017 and the allowance for doubtful accounts see "Item 18 – note 11 of the Notes on Consolidated Financial Statements".

Market risk

In the normal course of its operations, Eni is exposed to market risks deriving from fluctuations in commodity prices and changes in the euro versus other currencies exchange rates, particularly the U.S. dollar, and in interest rates. For a description of how the Company manages the Market risk see "Item 18 – note 38 of the Notes on Consolidated Financial Statements".

Research and development

For a description of Eni's research and development operations in 2017, see "Item 4 – Research and development".

TABLE OF CONTENTS

Item 6. DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

Directors and Senior Management

The following table lists the Company's Board of Directors as at March 2018:

Name	Position	Year elected or appointed	Age
Emma Marcegaglia	Chairman	2014	52
Claudio Descalzi	CEO	2014	63
Andrea Gemma	Director	2014	44
Pietro A. Guindani	Director	2014	60
Karina A. Litvack	Director	2014	55
Alessandro Lorenzi	Director	2011	69
Diva Moriani	Director	2014	49
Fabrizio Pagani	Director	2014	51
Domenico Livio Trombone	Director	2017	57

In accordance with Article 17.1 of Eni's By-laws, the Board of Directors is made up of 3 to 9 members.

The current Board of Directors was elected by the ordinary Shareholders' Meeting held on April 13, 2017 which also established the number of Directors at nine for a term of three financial years. The Board's term will therefore expire with the Shareholders' Meeting called to approve the financial statements for the year ending December 31, 2019.

The Board of Directors is appointed by means of a slate voting system: slates may be presented by the shareholders representing at least 0.5% of share capital. According to the Eni By-laws, three out of nine Directors are appointed from among the candidates of the non-controlling shareholders.

Emma Marcegaglia, Claudio Descalzi, Andrea Gemma, Diva Moriani, Fabrizio Pagani and Domenico Livio Trombone were the candidates of the Ministry of the Economy and Finance. Pietro A. Guindani, Karina Litvack and Alessandro Lorenzi were the candidates of institutional investors (non-controlling shareholders). The Shareholders' Meeting appointed Emma Marcegaglia as the Chairman of the Board of Directors and, on April 13, 2017, the Board appointed Claudio Descalzi as the Chief Executive Officer of the Company.

Three Directors out of nine, including the Chairman, were drawn from the less represented gender, reaching the ratio of one-third of the Directors as provided by the law.

The following provides details on the personal and professional profiles of the Directors.

Emma Marcegaglia was born in Mantua in 1965 and has been Chairman of Eni since May 2014. She has been Chairman of the Fondazione Eni Enrico Mattei since November 2014. She is also Chairman and CEO of Marcegaglia Holding SpA and Deputy Chairman and CEO of the subsidiary companies operating in the processing of steel. She is also Chairman and CEO of Marcegaglia Investments Srl, the holding company of the diversified activities of the group. She is President of Businesseurope and of the Luiss Guido Carli University, a member of the Board of Directors of Bracco SpA and Gabetti Property Solutions SpA. From 1994 to 1996 she was National Deputy President of Young Entrepreneurs of Confindustria, from 1997 to 2000 she was President of the European Confederation of the Young Entrepreneurs (YES), from 1996 to 2000 President of Young Italian Entrepreneurs of Confindustria and from 2000 to 2002 she was Vice President of Confindustria for Europe. From May 2004 to May 2008 she was Confindustria Vice President for infrastructures, energy, transport and environment and Italian Representative of the top High Level Group for energy, competitiveness and environment set up by the European Commission. From May 2008 to May 2012 she was President of Confindustria. She was a member of the Management Board of Banco Popolare and Director of Finecobank SpA and Italcementi SpA. She also held the position of Chairman of the Aretè Onlus Foundation. She graduated with a degree in business administration from the Bocconi University in Milan and attended a Master's in Business Administration at New York University.

TABLE OF CONTENTS

Claudio Descalzi was born in Milan and has been Eni's CEO since May 2014. He is a member of the General Board and of the Advisory Board of Confindustria and Director of Fondazione Teatro alla Scala. He is a member of the National Petroleum Council for 2016/2017. He joined Eni in 1981 as Oil & Gas field petroleum engineer and then became project manager for the development of North Sea, Libya, Nigeria and Congo. In 1990 he was appointed Head of Reservoir and operating activities for Italy. In 1994, he was appointed Managing Director of Eni's subsidiary in Congo and in 1998 he became Vice President & Managing Director of Naoc, a subsidiary of Eni in Nigeria. From 2000 to 2001 he held the position of Executive Vice President for Africa, Middle East and China. From 2002 to 2005 he was Executive Vice President for Italy, Africa, Middle East, covering also the role of member of the board of several Eni subsidiaries in the area. In 2005, he was appointed Deputy Chief Operating Officer of Eni's Exploration & Production Division. From 2006 to 2014 he was President of Assomineraria and from 2008 to 2014 he was Chief Operating Officer of Eni's Exploration & Production Division. From 2010 to 2014 he held the position of Chairman of Eni UK. In 2012, Claudio Descalzi was the first European in the field of Oil & Gas to receive the prestigious "Charles F. Rand Memorial Gold Medal 2012" award from the Society of Petroleum Engineers and the American Institute of Mining Engineers. He is a Visiting Fellow at The University of Oxford. In December 2015 he was made a member of the "Global Board of Advisors of the Council on Foreign Relations". In December 2016 he was awarded an Honorary Degree in Environmental and Territorial Engineering by the Faculty of Engineering of the University of Rome, Tor Vergata. He graduated with a degree in physics in 1979 from the University of Milan.

Andrea Gemma was born in Rome in 1973 and has been Director of Eni since May 2014. He is Professor of Private Law at The Third University of Rome and was visiting professor at European Universities and at Villanova University. Member of the Strategic Board of the American University of Rome and Appeal Court Lawyer. He is also Chairman of Serenissima SGR SpA and member of the Board of Directors of Banca UBAE SpA and of Global Capital PLC. He is President of Board of Statutory Auditors of PS Reti S.p.A. and Sirti S.p.A. He is also Official Receiver of Valtur SpA, Liquidator of Novit Assicurazioni SpA and Sequoia Partecipazioni SpA.

Pietro A. Guindani was born in Milan in 1958 and has been Director of Eni since May 2014. Since July 2008 he has been Chairman of the Board of Directors of Vodafone Italia SpA, where between 1995-2008 he was Chief Financial Officer and subsequently Chief Executive Officer. He previously held positions in the Finance Departments of Montedison and Olivetti and started his career in Citibank after graduating in Business at the Università Luigi Bocconi in Milan. He is currently also Board member of Salini-Impregilo SpA, the Italian Institute of Technology and Cefriel-Polytechnic of Milan. He is Board Member of Confindustria and Member of the Executive Board of Confindustria Digitale; he is President of Asstel-Assotelecomunicazioni and Vice President responsible for Universities, Innovation and Human Capital of Assolombarda. He was also Director of Société Française du Radiotéléphone – SFR S.A. (2008-2011), Pirelli & C. SpA (2011-2014), Carraro SpA (2009-2012), Sorin SpA (2009-2012) and Finecobank SpA (2014-2017).

Karina A. Litvack was born in Montreal in 1962 and has been a Director of Eni since May 2014. She is currently a member of the Global Advisory Council in Cornerstone Capital Inc., a member of the Advisory Board in Bridges Ventures LLC, a member of the CEO Sustainability Advisory Panel in SAP AG, a member of Business for Social Responsibility and of Yachad, a member of the Advisory Council for Transparency International UK and a member of the Senior Advisory Panel of Critical Resource. From 1986 to 1988 she was a member of the Corporate Finance team of PaineWebber Incorporated. From 1991 to 1993 she was a Project Manager of the New York City Economic Development Corporation. In 1998 she joined F&C Asset Management plc where she held the position of Analyst Ethical Research, Director Ethical Research and Director Head of Governance and Sustainable Investments (2001-2012). She was also a member of the Board of the Extractive Industries Transparency Initiative (2003-2009) and of the Primary Markets Group of the London Stock Exchange Primary Markets Group (2006-2012). She graduated in Political Economy at the University of Toronto and in Finance and International Business from Columbia University Graduate School of Business.

Alessandro Lorenzi was born in Turin in 1948 and has been Director of Eni since May 2011. He is a founding partner of Tokos Srl, a consulting firm for securities investment, Director of Ersel SIM SpA and of Mutti SpA. He began his career at SAIAG SpA in the Administration and Control area. In 1975 he joined Fiat Iveco SpA where he held a series of positions: Controller of Fiat V.I. SpA, Head of Administration, Finance and Control, Head of Personnel of Orlandi SpA in Modena (1977-1980) and

Project Manager (1981-1982). In 1983 he joined GFT Group where he was Head of Administration, Finance and Control of Cidat SpA, a GFT SpA subsidiary (1983-1984), Central Controller of GFT Group (1984-1988), Head of Finance and Control of GFT Group (1989-1994) and Managing Director of GFT SpA, with ordinary and extraordinary powers over all operating activities (1994-1995). In 1995 he was appointed Chief Executive Officer of SCI SpA, where he oversaw the restructuring process. In 1998 he was appointed Operating Officer and was subsequently Director of Ersel SIM SpA until June 2000. In 2000 he became Executive Officer of Planning and Control at the Ferrero Group and General Manager of Soremartec, the technical research and marketing company of the Ferrero Group. In May 2003 he was appointed CFO of Coin Group and in 2006 he became Chief Corporate Officer at Lavazza SpA, becoming Board member from 2008 to June 2011. From July 2011 to September 2017 he was Chairman of Società Metropolitana Acque Torino SpA.

Diva Moriani was born in Arezzo in 1968 and has been a Director in Eni since May 2014. She is currently Executive Vice Chairman of Intek Group SpA, Vice Chairman of KME AG, a German holding company of KME Group, Director of KME S.r.l., Member of the Supervisory Board of KME Germany GmbH and Director of Assicurazioni Generali SpA, Moncler SpA, Dynamo Academy, Dynamo Foundation and Associazione Dynamo. From 2007 to 2012 she was CEO of I2Capital Partners, a private equity fund sponsored by Intek Group SpA, with an investment strategy focused on “Special Situations” and from 2014 to 2017 CEO of KME AG. She graduated in Economics at the University of Florence.

Fabrizio Pagani was born in Pisa in 1967 and has been a Director in Eni since May 2014. He is currently the Head of the Technical Secretariat of the Ministry of Economy and Finance. He was Deputy Director of the International Training Programme for Conflict Management at the High School S. Anna in Pisa from 1995 to 1998, Professor of International Law in the Faculty of Political Science at the University of Pisa from 1993 to 2001, Deputy Chief of the Legislative Office at the Department of European Affairs from 1998 to 1999 and Counsellor for International Affairs in the Ministry of Industry and Foreign Trade from 1999 to 2001. He was Senior Advisor at the OECD from 2002 to 2006, Head of the Office of the State Undersecretary, within the Prime Minister Office from 2006 to 2008, board member of SACE SpA from 2007 to 2008, Political Counsellor of the OECD General Secretary from 2009 to 2011, Director of the G8/ G20 Office at the OECD from 2011 to 2013 and Senior Economic Counsellor to the Prime Minister and G20 Sherpa from 2013 to 2014. He was a NATO Fellow and was a visiting scholar at Columbia University, New York. He graduated in international studies at the Scuola Superiore Sant’Anna, Pisa, and has a Master Degree from the European University Institute, Florence.

Domenico Livio Trombone was born in Potenza in 1960 and has been Director of Eni since April 2017. He is a certified chartered accountant and a certified public auditor. He is partner of Studio Trombone Dottori Commercialisti e Associati. He is currently Chairman of the Board of Directors of Carimonte Holding SpA, of Consorzio Cooperative Costruzioni – CCC, of Focus Investments SpA and of Società Gestione Crediti Delta SpA. Furthermore, he is Director of La Centrale Finanziaria Generale SpA and of Aeroporto Guglielmo Marconi di Bologna SpA. He is also Chairman of the Board of Statutory Auditors of Associazione Costruttori Italiani Macchine Attrezzature per Ceramica (Acimac), Coop Alleanza 3.0 Sc and of Unipol Banca S.p.A. He is standing Statutory Auditor, among the others, of: Arca Assicurazioni SpA, Arca Vita SpA, CCFS Soc. Coop, Cooperare SpA, Parco SpA, Popolare Vita SpA, Unipol Finance Srl and Unipol Investment SpA. He is Liquidator in Italcarni Sc and Judicial Commissioner and Liquidator in Open.Co S.c. He is technical consultant in legal proceedings, coadjutor in bankruptcy proceedings, liquidator, trustee in bankruptcy and judicial commissioner. Over the years he held positions in banks, in asset management and insurance companies. More in detail, he was standing Statutory Auditor in Carimonte Holding SpA, Unicredit Servizi Informativi SpA, Immobiliare Nettuno Srl and Gespro SpA. From April 2006 to March 2007 he was Director of Aurora Assicurazioni SpA. From October 2007 until the merger of the Company in FonSai SpA, he was Chairman of the Board of Statutory Auditors in Unipol Assicurazioni SpA. Until December 2008 he was Director in Banca Popolare del Materano SpA and BNT Consulting SpA. From April 2010 to October 2011 he was Chairman of the Board of Directors in BAC Fiduciaria SpA. From April 2009 to December 2011 he was Chairman of the Board of Statutory Auditors in Arca Impresa Gestioni SGR SpA. From April 2007 until April 2012 he was Chairman of the Board of Statutory Auditors in Cassa di Risparmio di Cento SpA. Since April 2010 to May 2016 he held the position of Chief Executive Officer in Carimonte Holding SpA. From December 2011 to December 2012 he was independent Director in Serenissima SGR SpA. From December 2011 to April 2016 he was Director and Vice Chairman in

Gradiente SGR SpA. From April 2007 to April 2016 he was Standing Statutory Auditor of Unipol Gruppo Finanziario SpA. He graduated in Economics from the University of Modena.

133

TABLE OF CONTENTS

Senior Management

The table below sets forth the composition of Eni's Senior Management as at December 31, 2017. It includes the CEO, as General Manager of Eni SpA, as well as the Chief Officers and the Executives who report directly to the CEO and to the Board, and on its behalf, to the Chairman, and the CEOs of Eni subsidiaries who are members of Eni's Management Committee.

Name	Management position	Year first appointed to current position	Total number of years of service at Eni	Age
Claudio Descalzi	CEO and General Manager of Eni	2014	36	62
Luca Bertelli	Chief Exploration Officer	2014	33	59
Roberto Casula	Chief Development, Operations & Technology Officer	2014	29	55
Claudio Granata	Chief Services and Stakeholder Relations Officer	2014	34	57
Massimo Mantovani	Chief Gas & LNG Marketing and Power Officer	2016	24	54
Massimo Mondazzi	Chief Financial Officer	2014	25	54
Giuseppe Ricci	Chief Refining & Marketing Officer	2016	32	59
Antonio Vella	Chief Upstream Officer	2014	34	60
Marco Bollini	Legal Affairs Department Senior Executive Vice President	2016	20	51
Marco Petracchini	Internal Audit Department Senior Executive Vice President	2011	18	53
Roberto Ulissi	Corporate Affairs and Governance Department Senior Executive Vice President and Board Secretary and Corporate Governance Counsel	2006	11	55
Marco Bardazzi	External Communication Department Executive Vice President	2015	2	50
Luca Cosentino	Energy Solutions Department Executive Vice President	2015	14	56
Lapo Pistelli	International Affairs Department Executive Vice President	2017	2	53
Luca Franceschini	Integrated Compliance Department Executive Vice President	2016	26	51
Jadran Trevisan	Integrated Risk Management Executive Vice President	2016	17	56
Alberto Chiarini	CEO of Eni gas e luce SpA	2017	28	54
Daniele Ferrari	CEO of Versalis SpA	2011	6	56
Vincenzo Maria Larocca	CEO of Syndial SpA	2016	31	56

The Chief Exploration Officer, the Chief Development, Operations & Technology Officer, the Chief Upstream Officer, the Chief Gas & LNG Marketing and Power Officer, the Chief Refining & Marketing Officer, the Chief Financial Officer, the Chief Services & Stakeholder Relations Officer, the Senior Executive Vice President Legal Affairs Department, the Senior Executive Vice President Internal Audit Department, the Senior Executive Vice President Corporate Affairs and Governance Department, as well as the Executive Vice President Energy Solutions Department, the Executive Vice President External Communication Department, the Executive Vice President

International Affairs Department, the Executive Vice President Integrated Compliance Department, the Executive Vice President Integrated Risk Management, the Chief Executive Officer of Versalis SpA, the Chief Executive Officer of Eni gas e luce SpA, and the Chief Executive Officer of Syndial SpA are members of the Management Committee, which provides advice and support to the Chief Executive Officer. Other managers may be invited to attend meetings based on the agenda. The Chairman of the Board is invited to attend meetings. The duties of Committee Secretary are performed by the Senior Executive Vice President Corporate Affairs and Governance Department.

TABLE OF CONTENTS

The Chief Financial Officer has been appointed as Officer in charge of preparing Company's financial reports pursuant to Italian law by the Board of Directors, acting upon a proposal of the CEO in agreement with the Chairman, following consultation with the Nomination Committee and with the approval of the Board of Statutory Auditors.

The Senior Executive Vice President of the Internal Audit Department is appointed by the Board of Directors, acting upon a proposal of the Chairman in agreement with the Chief Executive Officer (in his capacity as Director in charge of the internal control and risk management system), following consultation with the Board of Statutory Auditors and the Nomination Committee and with the favorable opinion of the Control and Risk Committee.

The Board Secretary and Corporate Governance Counsel is appointed by the Board of Directors upon a proposal of the Chairman.

Other members of Eni's senior management are appointed by Eni's CEO and may be removed without cause.

Senior Managers

Luca Bertelli was born in Sesto Fiorentino on 5 October 1958. He graduated with honours in geology in 1983 from the University of Florence. In 1984 he joined Eni's geophysics division, working first as a researcher in the development of 3D seismic prospecting technology and subsequently as a manager of 3D seismic prospecting programmes, specialising in seismic-stratigraphy. In 1994 he was appointed manager of seismic-stratigraphy applications and in 1999 he increased the technical-managerial scope of his activities becoming manager of geological and geophysical services in Eni.

At the end of 2001, his career took a new international turn holding positions of increasing managerial complexity over a period of eight years, starting in Norway where he was Technical Director and Deputy Managing Director at Norsk Agip in Norway. In 2003 he was appointed Managing Director of Eni Indonesia and in 2006 he moved to Egypt as General Manager and Managing Director, a position he also held at Eni Angola in 2007. In 2009 he returned to Eni's headquarters as Senior Vice Chairman of Global Exploration. He was appointed Executive Vice President of Exploration and Unconventional at the beginning of 2010. Since July 1, 2014, he has been Eni's Chief Exploration Officer.

Roberto Casula was born in Cagliari in 1962. He graduated in mining engineering from the University of Cagliari. He joined Eni in 1988 as a Reservoir Engineer. He spent the first years of his professional life working in oil fields in Italy before moving to West Africa, where he was appointed Chief Development Engineer. He returned to Headquarters in 1997 as coordinator of Business Development activities for Africa and the Middle East, contributing to a number of new initiatives and portfolio activities. In 2000, he became Technical Services Manager and in 2001 moved to the Middle East as Project Director on a giant gas production project. From 2004 to 2005, he held a number of managerial positions in Eni's Exploration & Production Division, eventually becoming the Chief Executive Officer of Eni Mediterranea Idrocarburi S.p.A., where he was involved in oil and gas exploration and production in Sicily. At the end of 2005, he was appointed Managing Director of Eni's subsidiaries in Libya, where he remained for two years and concluded the renegotiation of oil contracts and launched an important programme of social projects. In October 2007, he became head of operational and business activities for sub-Saharan Africa as Senior Vice President. In December 2011, he was appointed Executive Vice President of Eni's Exploration & Production Division and his responsibilities were extended to include the entire African continent and the Middle East region, also coordinating the Mozambique programme for the development of the Mamba and Coral discoveries. From 2014 to May 2016, he was a member of the Board of Directors of the Eni Foundation.

He has been Chairman of Versalis S.p.A. since January 2017. He has been Chairman of the Italian Petroleum and Mining Association since May 2016. Since July 1, 2014, he has been Eni's Chief Development, Operations & Technology Officer.

Claudio Granata was born in Rome in 1960. Graduating with a degree in economics, he joined the Eni group in 1983. From 1983 to 1994 worked as a labour market and social welfare expert with ASAP (the trade union association for Eni Companies). From 1994 to 1999 he continued his experience with Eni Corporate as an expert in industrial relations. In 2000 he was made responsible for Staff and Organisation within Eni Servizi Amministrativi, a company that was set up to centralise Eni's administrative activities.

TABLE OF CONTENTS

In 2001 he took over the management of Eni's territorial divisions, restructuring the management of staff by geographical area and in 2003 he took on the role of Business HR for Eni Corporate, ensuring support for departments in the management and development of Eni Corporate's managerial resources during a period of profound change (2002-2004), which was characterised by the mergers of Snam and AgipPetroli and the restructuring of staff organisation. In the same year he was also appointed head of Human Resources and Organisation of SOFID (Eni's financial services company).

In 2006 he was appointed Human Resources Director of the E&P Division, where he oversaw the planning, management, development and compensation processes for human resources and organisation activities. He also collaborated with the top management in the reorganisation of macro processes for the division and promoted change management initiatives.

He became a board member of Eni International Resources Ltd in 2006 and was Chairman of the board of Eni International Resources Ltd from 2012 to 2013. From 2012 to March 2015 he was a board member of Eni UK ltd.

In 2013 he was appointed Executive Vice President Sustainable Development, Safety, Environment and Quality at E&P, responsible for overseeing safety, environment and quality processes to promote integration with operational processes and contribute to improvements in "time to market" and efficiency. From 2014 to May 2016, he was a member of the Board of Directors of the Eni Foundation. He has been Chairman of the board of Eni Corporate University since November 2014. He has been Chief Services & Stakeholder Relations Officer in Eni since 1 July 2014.

Massimo Mantovani was born in Milano in 1963. He graduated with a degree in law from the University of Milan and holds a Master's Degree from the University of London. He is the author of numerous publications. After qualifying to practice law in Italy and UK he worked for few years in private legal practice in Milan and London. In 1993 he joined Eni's Legal Department, specializing in international negotiations and contracts, specifically on international gas/LNG supplies and projects and joint ventures for the commercialization and transport of gas. In 2001 he was appointed legal Director of Eni's Gas & Power Division. His main task was participating to the management for Eni of the start-up phase of the liberalization of the gas market in Italy and the unbundling of the national and international network for the transport of gas. In October 2005 he was appointed Senior Executive Vice President of Legal Affairs in Eni S.p.A. He has been Chief Legal and Regulatory Affairs in Eni from 2014 to 2016, the department managed all legal and energy regulatory issues of Eni and its non-listed subsidiaries. From 17 October 2016 to 3 August 2017 he has been Chief Midstream Gas & Power Officer.

From 2005 to 2016 he was member of Eni S.p.A. Watch Structure. He was a member of the Board of Directors in Snam Rete Gas S.p.A. from 2005 to 2012 and of the Board of University of Bologna from 2011 to 2012.

He has been Chairman of Syndial S.p.A. from 2016 to 2017. Since November 2016 Mr. Mantovani seats on behalf of Eni in the Governing Board and in the Executive Committee of Eurogas, the association representing the European gas sectors firms. He is Chairman of Anigas, the Italian association of Gas industry, from December 2017 and member of the Confindustria Energia presidential board.

Between 2011 and 2014 he has been a member of the anticorruption working group for the B20, coordinator for activities relating to the development of an international regulatory framework for the B20 held in Russia in 2013 and leading expert for the 2014 B20 in Australia.

He is Eni's Chief Gas & Lng Marketing and Power Officer since 4 August 2017.

He is Chairman of Eni Trading & Shipping S.p.A. since November 2016 and from February 2018 he has also been appointed CEO of the company in charge of Gas, LNG and Power activities.

Massimo Mondazzi was born in Monza in 1963. He graduated in Economics and Business Administration from Bocconi University Milan in 1987.. He joined Eni in 1992 after acquiring considerable professional experience in industrial companies and also as a management consultant. He worked in the Administration and Control area of the Exploration and Production Division until 2006, becoming Director. From 2006 to 2009 he was Director of Planning and Control for the Eni Group, before returning to E&P as Executive Vice President for the Central Asia, Far East and Pacific Region business areas. In this role he contributed to the consolidation of Eni's activities in the Exploration and Production division, to the launch of new development projects and to Eni's entry into new countries. On December 5, 2012 he was appointed Chief Financial Officer of Eni and Officer charged with preparing the company's financial reports pursuant to Article 154-bis of Legislative Decree No. 58/1998. He is Chairman of Agi S.p.A. since 2013. From

2014 until September 2016, alongside his role as Eni's Chief Financial Officer, he was also responsible for Eni's Integrated Risk Management department.

136

TABLE OF CONTENTS

Giuseppe Ricci was born in Casale Monferrato in 1958. He has a degree in chemical engineering. He joined Eni in 1985 initially working in the study and development of new refining processes at the Sannazzaro refinery, before becoming involved in the creation and consolidation of the joint venture with Kuwait Petroleum at the Milazzo refinery. In 2000 he returned to head office as where he was responsible for Refining Processes Development and oversaw the performance optimisation at the refining facilities of Agip Petroli. He left central technologies to take over, in 2004, as director of the Gela Refinery, a particularly challenging assignment both from a managerial perspective and in terms of the refining cycle and the complexity of the plant; in 2006 he was appointed managing director of the refinery. In June 2010 he was made Senior Vice President of the Industrial Sector for Refining & Marketing, with responsibility for the refineries, storage deposits, oil pipelines and plant and facilities in Italy, as well as the management of subsidiary and associated companies in Italy and abroad. As Industrial Director he also held a series of additional responsibilities, such as the chairmanship of Gela and Milazzo. In 2012 he took on the delicate role of Eni’s Executive Vice President Health, Safety Environment and Quality with responsibility for providing the guidelines, coordination and control of safety, industrial health, product safety, the environment and quality. Since 2016 he has been a board member of Eniservizi. He was appointed as Chief Refining & Marketing Officer on September 12, 2016.

Antonio Vella was born in 1957. He graduated with a degree in engineering from the Turin Polytechnic in 1982 and joined the Eni Group in 1983. He began his career as an oil engineer at Agip in Libya, where he was involved in upstream onshore and offshore operations. From 1988 to 1991, he was project manager for EniChem’s petrochemical plants and refineries in Italy. In 1991, he was appointed project manager for the development of Libyan oil fields and in 1993, he moved to Egypt, initially as Operations Manager and subsequently as General Manager and Managing Director of Petrobel, where he was responsible for all of Eni’s upstream operations in Egypt. In 1999, he was appointed District General Manager of Nigerian Agip Oil Co (NAOC), and in 2000, became Vice Chairman and Managing Director of the Eni companies in Nigeria NAOC, NAE (Nigerian Agip Exploration) and AENR (Agip Energy). In 2002, he became regional Vice President for Australasia, Russia, Azerbaijan and then, in 2005, a Member of the Board of Directors and Managing Director of Eni Algeria. From 2006 to 2009, he was regional Senior Vice President for North Africa and the Middle East (Algeria, Tunisia, Egypt, Libya, Mali, Morocco, Iran, Iraq and Saudi Arabia) for Eni’s Exploration & Production Division. In 2009, he was appointed Executive Vice President Operations for the Exploration & Production Division. In December 2012, he was appointed Executive Vice President for Central Asia, the Far East and the Pacific Area. Since July 2014, he has been a Board Member of Eni Foundation. Since July 1, 2014, he has been Chief Upstream Officer.

Marco Bollini was born in Milan in 1966. He graduated with a degree in law from the University of Milan and he is registered to practice law on the special list of the Ordine degli Avvocati (the Italian bar association) of Milan. After graduating, he worked as a lawyer for a few years in a law firm in Milan. He joined Eni in 1997 in the Legal Department of Agip S.p.A., mainly following international legal projects until 2001 when he took on the responsibility of International Legal Assistance of Exploration and Production Division. In 2005 he was appointed Legal Director of the Gas &Power Division, further diversifying his business knowledge. In 2007, he is back in the Exploration & Production Division as Legal Director. In 2008, following the centralization of the Eni’s legal function into one Legal Department, he took on responsibility for the legal assistance to the company’s activities outside Europe. In 2013 he was appointed Executive Vice President International Business Legal Area and, in 2015, he became Executive Vice President International and Finance Legal Affairs of Eni, with a strong exposure to international matters, with a particular focus on the Upstream business and management of partnerships and M&A transactions. Since 2016, he has been a Board Member of Eni Foundation. He was appointed Senior Executive Vice President Legal Affairs on October 17, 2016.

Marco Petracchini was born in Rome in 1964. He graduated Cum Laude with a degree in economics from La Sapienza University in Rome in 1989. After graduation, he was hired by Esso Italiana where he held various positions in the IT, Finance and Auditing sectors. He joined Eni in 1999 in the Internal Audit Department, gradually taking on positions of increasing responsibilities: Head of Downstream Audit activities and Head of Support Process Audit activities (in particular IT and Fraud Audit). He is also a Member of the Watch Structure of Eni SpA and Secretary of the Control and Risk Committee of Eni SpA. He holds international qualifications as well, in detail: Certified Internal Auditor (CIA), Certified Fraud Examiner (CFE), Certified Risk Management Assurance (CRMA). He is currently a

Board Member of AiiA (Italian Internal Auditors Association). He is Eni's Senior Executive Vice President Internal Audit Department.

137

TABLE OF CONTENTS

Roberto Ulissi was born in Rome in 1962. He's a lawyer. After a number of years spent as a lawyer at the Bank of Italy, in 1998, he was appointed General Manager at the Ministry of the Economy and Finance, head of the Banking and Financial System and Legal Affairs Department. He was a Board member of Telecom Italia (and Chairman of the Audit Committee), Ferrovie dello Stato, Alitalia, Fincantieri and a government representative on the Governing Council of the Bank of Italy. He is a board member and Vice Chairman of Banor SIM. He was also a member of numerous Italian and European committees representing the Ministry of the Economy, including, at a national level, the Commission for the Reform of Corporate Law (Commission "Vietti") and, at EU level, the Financial Services Policy Group, the Banking Advisory Committee, the European Banking Committee, the European Securities Committee, and the Financial Services Committee. He was also special professor of banking law at the University of Cassino. He is Grande Ufficiale della Repubblica Italiana. Since 2006, he has been Senior Executive Vice President Corporate Affairs and Governance and a Board Member of Eni International BV. He is currently Board Secretary of Eni and, since 2014, Corporate Governance Counsel.

Marco Bardazzi was born in Prato in 1967. He is a professional journalist working in the media world for 28 years before joining Eni in 2015. He has gained extensive experience on foreign policy and digital communications, particularly in Europe and America. Between 2009 and 2015 he was Managing Editor and Digital Editor at "La Stampa". He was a key member of the team that worked on the transformation of a traditional newspaper to an integrated digital news organization, creating an innovative "concentric circles" multiplatform newsroom. He was one of the co-founders of "Europa" a partnership between La Stampa, Le Monde, El País, The Guardian, Gazeta Wyborcza and Suddeutsche Zeitung. Before joining "La Stampa", he was U.S. correspondent for the Italian news agency ANSA between 2000 and 2009, covering every aspect of American life for the Italian media. Among other things, he covered the Bush-Gore electoral race for the White House in 2000, the first international Al Qaeda trial in Manhattan, the September 11 attack on America, the wars in Afghanistan, and Iraq and the 2004 and 2008 presidential campaigns. He has visited and reported on the Guantanamo detention camp at the U.S. Navy Guantanamo Bay base in Cuba. He won the Saint-Vincent Award for Journalism for a series of reports on the death penalty in the USA. He covered the 2008 financial crisis, and he reported extensively on the American digital, energy and automobile industries.

He holds an Associate of Arts degree in History from American Public University. His latest book is "L'Ultima Notizia" (with Massimo Gaggi, Rizzoli 2010), an essay on digital transformation in the media business. He is an external lecturer in the Masters in Journalism in ALMED-Università Cattolica del Sacro Cuore, Milan.. He is a Visiting Fellow at the University of Oxford. In 2017 he was appointed as a Director of Agi SpA and Eni Gas e Luce. Since February 2015, he has been External Communication Department Executive Vice President.

Luca Cosentino was born in Venice on August 1, 1961. He graduated cum laude with a degree in geology in 1985 from the University of Padua and joined Eni in 1986. He spent the first years of his professional life in the Reservoir Department, within the reservoir modeling group. Between 1992 and 1996, he worked in different operational positions in Italy and abroad in the reservoir sector. From 1996 to 2003, he worked as Project Manager with IFP (Institut Français du Petrol, France), in Venezuela and in the Persian Gulf. In this period, he also taught at the IFP School and published several technical papers, including a book on Integrated Reservoir Studies. Upon his return to Eni in 2003, he was appointed Head of the Reservoir Department and, in 2004, Head of the Reservoir Modeling Department. From 2005 to 2010, he was in Libya, initially as Operation and Asset Manager with Eni North Africa and then as Member of the Management Committee in the operating company Eni Oil, later Mellitah Oil & Gas. From 2010 to 2013, he has been Managing Director of Eni Congo. In 2013, he was appointed Senior Vice President Non Operated Business Performance and Stranded Resources Valorization. Since November 1, 2015, he has been Executive Vice President Energy Solutions Department.

Lapo Pistelli was born in Florence in 1964. Having graduated with honors in 1988 in International Law at the Political Science faculty "Cesare Alfieri" at the University of Florence, he started working at a research center, while serving for two mandates in the local administration of Florence. He was member of the Italian Parliament from 1996 to 2015 (1996/2004 and 2008/2015), and also member of the European Parliament (2004/2008). As an Italian MP, he was member of the Committees on Constitutional Affairs, European Affairs and on International Affairs. As a MEP in Brussels, he worked at the Economic and Monetary Affairs and Foreign Affairs Committees. During this period, he has also been the President of the EU-South Africa Delegation and a member of the Italian Delegation to the OSCE, where he conducted several monitoring missions in transitional democracies.

TABLE OF CONTENTS

He served as Deputy Minister of Foreign Affairs and International Cooperation of Italy from 2013 to 2015. He resigned from all his institutional and political roles in July 2015, when he entered Eni as Senior Vice President for Strategic Analysis for Business Development Support. He was appointed Executive Vice President in April 2017. He taught and lectured at the University of Florence, the Overseas Studies Program of Stanford University and many others international academic institutions. He regularly contributed to many European and American think tanks and research centers specialized in international relations. He is a member of the board of the European Council on Foreign Relations (ECFR), of the Istituto Affari Internazionali (IAI), of the editorial board of Oil and of the scientific committee of EastWest. As a journalist, he regularly publishes in various newspapers issues related to European and international affairs and on specialized magazines, such as Limes. He authored several publications: in his last book, Il nuovo sogno arabo – Dopo le rivoluzioni, Feltrinelli 2012, he analyses the origin and challenges of the 'Arab Spring' and its impact on the geo-political scenario in North Africa and the Middle East.

Luca Franceschini was born in Milan in 1966. He is a graduate in Law from the University of Milan and is registered to practice law on the special list of the Ordine degli Avvocati (the Italian Bar association) in Rome. He first joined in Eni in 1991 in the legal department of Agip S.p.A., initially involved in disputes and providing legal assistance to the procurement area, before going on to delivering legal support for a range of national and international projects in the Exploration & Production sector. In 2000, in the context of the process for the liberalisation of the natural gas sector, he was involved in the spin-off of the gas storage business and the creation and launch of Sogit SpA, for which he became head of Legal and Corporate Affairs. He made his return to Eni Spa in 2005 as head of Italian Legal Assistance in the Gas & Power division. Following the concentration of all legal functions in Eni's central Legal Department, he was engaged in providing legal support in the regulatory and antirust areas, gradually extending his responsibilities and becoming, in 2009, head of Legal Assistance for the business and Antitrust issues in Italy, as well as council for legal assistance for the activities of the Refining & Marketing sector. He was also a member of the boards of directors of both Italgas and Stogit. In 2015 he was appointed as Eni's Executive Vice President for Legal and Regulatory Compliance. He was appointed as Executive Vice President of Integrated Compliance on September 12, 2016.

Jadran Trevisan was Born in Milan in 1961. He has a degree in philosophy and a Master's in business administration from SOGEA, the management school of Confindustria Liguria. After a short period at Gabetti, in 1991 he joined the Fininvest Group, where he was involved in financial communications and was part of the project for the listing of Mediaset for which, in 1995, he became the Investor Relations Manager. In 2000 he joined Eni as head of Investor Relations, where, in addition to participating in a number of significant extraordinary operations (the listing of Snam Rete Gas, the de-listing of Italgas), he oversaw relations with institutional investors. In 2006 he was appointed head of Business Strategy at Eni's E&P division, where he was involved in the acquisition of significant assets and companies operating in the upstream sector. In 2008 he was appointed CFO of the recently acquired subsidiary Distrigas, where, for the following three years, he was engaged in consolidating and aligning the company's business and financial processes with those of Eni and rationalising the company structure. In 2011 he was part of the project for the creation of Eni Trading & Shipping SpA, becoming its Senior Vice President for Operations & Control. From the end of 2012 until July 2015 he was Senior Vice President Credit and in August 2015 he was appointed Senior Vice President for Integrated Risk Management. Since September 12, 2016 he reports directly to the Chief Executive Officer in his role as Executive Vice President Integrated Risk Management.

Alberto Chiarini was born in Milan in 1963. After taking a degree in political science and a specialization at the Scuola Enrico Mattei, he joined Eni in 1989. He began his career in an international context, where he had assignments of growing responsibility in the Finance function in a number of countries (including the United Kingdom, Congo, Libya and Netherlands), until he raised to the position of Managing Director of Eni UK. He returned to Italy in 2006 as head of Planning and Control at the Exploration and Production division. Later, he was appointed as Eni's Executive Vice President Global Procurement and Strategic Sourcing. In 2011, he was appointed Chief Executive Officer of Syndial, the Eni subsidiary that provides integrated services in the field of environmental remediation. By the end of 2013, he was appointed Chief Financial and Compliance Officer of Saipem SpA, holding the levers of Finance, Legal Affairs & Compliance and ICT, overseeing in particular the recapitalization and refinancing of the company. In 2016, he was appointed Chief Retail Market Gas & Power Officer of Eni SpA. In this role he led the spin-off of the retail gas & power business of Eni and the establishment, in 2017, of Eni gas e luce

TABLE OF CONTENTS

SpA, the new Eni subsidiary dedicated to commercialization of gas, power and services. Since then, he is Chief Executive Officer of Eni gas e luce SpA, and in this role he is leading a major transformation of the company, based on products innovation and business processes digitalization.

Daniele Ferrari, 56, is Chief Executive Officer of Versalis SpA and Chairman of Matrica SpA, the joint-venture with Novamont on renewable chemistry. Under his leadership in 2012, the Eni chemical company has undertaken a significant strategic move from a former "Polimeri Europa" into a new "Versalis" through the repositioning of its asset base, geography and portfolio by emphazising R&D, leveraging licensing and new global partnerships. With over 30 years in the chemical industry, he began his career at InterWat (Idreco group), a water treatment engineering company. In 1982 he moved to the Refining Technology unit of Agip Petroli and in 1986 he joined the Milan-based offices of ICI (Imperial Chemical Industries) where he held positions in a variety of areas including sales, technical development, chemicals and plastics marketing, and eventually serving as senior executive in 1990. Internationally, in 1992, he moved to the UK to join the "Klea" Fluorocarbons & Lubricants business headquarters following the business global development and subsequently taking over the position of EMEA Commercial Director of the business. In 1996 he headed to the ICI's Polyurethanes Brussels-based headquarters to serve as Global Business Unit Director for PU Intermediates. When Huntsman Corporation acquired the bulk of the ICI business in 1999 and the Rhodia-Albright & Wilson's European business, he was appointed Managing Director of the newly-integrated Huntsman Surface Science-Italy and, later Vice President EMEA of the Brussels-based Huntsman Performance Products Division in 2004. He was then named in 2008 President of the Performance Products Global Division, based in Houston, TX. Daniele Ferrari is also: President of PlasticsEurope, the European association of plastics manufacturers; Board member of CEFIC (Conseil Européen de l'Industrie Chimique, Brussels) and member of the Nominee Committee; Vice President of Federchimica (Italian Chemical Industry Council) for European Affairs and Economy; Board member of the OUBEP (Oxford University Business Economics Program); member of the Board of Directors and Chairman of the Compensation Committee of Venator Materials Plc.

Vincenzo Maria Larocca was born in Alberobello (BA) in 1961. He graduated in Law at Bari University and he started working for Eni in 1986 in the legal department providing national and international legal assistance for Enichem SpA. Then in 1993 he was responsible for International and community rights for Enichem SpA. At the same time as a member of "High Legal Strategy Group - Legal" and "Working Party on Competition Law", which was created by the Cefic (Conseil Européen des Fèdèrations de l'industrie chimique) for the monitoring of the evolution of the community rights, he represented Enichem and Federchimica. In 2002 he became Legal Affairs and Secretariat Director at Polimeri Europa. As such he dealt with matters related to extraordinary operations portfolio, contentious and environmental matters. In 2006 he was responsible for the Legal Assistance for petrolchemistry and Syndial SpA, with a particular focus on HSE and environmental law. Then in 2007 as a Legal Director he provided consultancy for Refining & Marketing Division in Italy and abroad. In 2008 he was appointed General Counsel of Industial Activities in Italy providing legal assistance in terms of exploration & production, refinery of crude oil and distribution of petrol, petrolchemistry and other activities. In addition, he provided legal assitance for HSE. In 2010 as SVP General Counsel for the Legal Compliance department he dealt with legal assistance related to business responsability, anticorruption, penal law and HSE for Eni. In 2011 he also managed the legal assistance for procurement at the headquarters and subsidiaries and in 2015 he was Legal and Penal Direction EVP. He has been CEO for Syndial SpA since September 2016.

Compensation

Board members' emoluments are determined by the Shareholders' Meeting, while the emoluments of the Chairman and CEO, in relation to the powers entrusted to them, are determined by the Board of Directors, which considers relevant proposals made by the Compensation Committee after examining the opinion of the Board of Statutory Auditors.

TABLE OF CONTENTS

Moreover, in accordance with the applicable Italian laws and regulations (Article 123-ter of Legislative Decree No. 58 of February 24, 1998 and Article 84-quater of Consob Decision No. 11971 of May 14, 1999, and subsequent modifications) and in line with the Corporate Governance Code recommendations for Italian listed companies, the Board of Directors approves and submits to the annual Shareholders' Meeting advisory vote, the first section of the Remuneration Report which describes the Remuneration Policy Guidelines adopted for Directors and other Managers with strategic responsibilities(9).

The main elements of the 2018 remuneration policy and of the compensation paid in 2017 to Directors, Statutory Auditors, CEO and General Manager and other Managers with strategic responsibilities, are described below.

2018 Remuneration Policy Guidelines

This chapter contains the Remuneration Policy Guidelines approved by the Board of Directors on March 15, 2018 for Directors and for other Managers with strategic responsibilities.

The 2018 Remuneration Policy Guidelines contain no substantial changes compared with what was previously described in the first section of the 2017 Remuneration Report examined by shareholders at the annual meeting of 13 April 2017, which was approved by favorable vote of 96.33% of those in attendance.

In this chapter, we also present the remuneration for Directors with delegated powers (i.e. the Chairman and the Chief Executive Officer and General Manager), as recommended by the Compensation Committee and having heard the opinion of the Board of Statutory Auditors, approved by the Board of Directors on 19 June and 27 July 2017. These resolutions were passed in line with the 2017 Remuneration Policy Guidelines and with the conditions of the 2017-2019 Long-Term Incentive Plan.

The Board took account of the elimination of the previous restrictions concerning the reduction of remuneration for executive directors of listed companies that are controlled, directly or indirectly, by government entities and of the results of comparative remuneration analyses with similar panels.

Market references and peer group

For the Chief Executive Officer and General Manager, the positioning of the Company's remuneration is assessed by comparing similar roles only in the international Oil & Gas sector, with regard to upstream activities in particular, and in line with the company's strategy to increase its focus on the business. More specifically, the comparator group includes the main listed companies in the Oil & Gas sector, which are Eni competitors at the international level and possess comparable business characteristics (Anandarko, Apache, BP, Chevron, Conoco Phillips, ExxonMobil, Marathon Oil, Shell, Statoil and Total).

This panel also constitutes the Peer Group used for the relative comparison of Eni performance in the new Long-Term Performance Share Plan.

For the Chairman and the Non-Executive Directors, the positioning of remuneration is assessed by comparing similar roles in the "Top Italy" panel, composed of the main companies listed on the FTSE MIB (Assicurazioni Generali, Atlantia, Enel, Intesa Sanpaolo, Leonardo, Luxottica, Mediaset, Mediobanca, Poste Italiane, Snam, Terna, TIM, Unicredit).

For Managers with strategic responsibilities, the positioning of remuneration is assessed by comparing roles with the same level of managerial responsibility and complexity in national and international panels of companies in the industrial sector.

(9)
Those persons who have the power and responsibility, directly or indirectly, for planning, directing and controlling Eni fall under the definition of "Managers with strategic responsibilities", pursuant to Consob regulations. Eni Managers with strategic responsibilities, other than Directors and Statutory Auditors, are those who sit on the Management Committee and, in any case, those who report directly to the Chief Executive Officer.

TABLE OF CONTENTS

General principle of clawback

Clawback mechanisms will be adopted, through a specific regulation proposed by the Compensation Committee and approved by the Board of Directors, allowing the variable remuneration components already paid and/or granted to be reclaimed, or those subject to deferral to be withheld, where their achievement was based on data that was subsequently proven to be manifestly misstated, or allowing the recoupment of all the incentives for the year (or years) in which subsequent checks confirm the fraudulent alteration of the results data used to obtain the right to incentives, and/or the commission of serious and deliberate violations of the law and/or regulations, the Code of Ethics or the Company rules, if relevant to the employment and trust relationship, without prejudice to any other action permitted by law and regulations to protect the interests of the Company. The regulation provides that the activation of recoupment claims (or revocation of incentives awarded but not yet paid) must take place, once the checks have been completed, within three years of payment (or award) in the case of error, and within five years in the case of fraud.

Chairman of the Board of Directors

Remuneration for the delegated powers

The 2018 Remuneration Policy Guidelines for the Chairman provide for total fixed remuneration of €500,000 gross, which includes: €90,000 gross for the position, as determined by the Shareholders' Meeting of 13 April 2017 and remuneration for exercise of delegated powers of €410,000 gross, as approved by the Board of Directors on 19 June 2017, taking account of the outcome of the comparative analyses of remuneration related to median levels in the benchmark market and the complexity of the position.

The 2018 Remuneration Policy provides also for life insurance policy and permanent disability insurance policy due to injury or illness contracted in the workplace or elsewhere.

Payments due in the event of termination of office or employment

No specific severance payments are provided for the Chairman, nor do any agreements exist for indemnities in the case of resignation or early termination of office.

Non-executive directors

Remuneration for participation on Board Committees

The 2018 Policy Guidelines for Non-Executive and/or Independent Directors provide for the maintenance of the additional annual remuneration for participating on Board Committees, as approved by the Board of Directors on 13 April 2017 and in line with the median levels recorded in the reference market, taking due account of the commitment in terms of frequency and duration of meetings, as follows:

- for the Control and Risk Committee, annual remuneration consists of €70,000 for the Chairman and €50,000 for the other members;
- for the Compensation Committee and the Sustainability and Scenarios Committee, the annual remuneration consists of €50,000 for the Chairman and €35,000 for the other members;
- for the Nomination Committee, the annual remuneration consists of €40,000 for the Chairman and €30,000 for the other members.

Payments due in the event of termination of office or employment

No specific severance payments are provided for the Non-Executive Directors, nor do any agreements exist for indemnities in the case of resignation or early termination of office.

Chief Executive Officer and General Manager

The 2018 Remuneration Policy Guidelines for the Chief Executive Officer and General Manager of the Company are in line with the 2017 Remuneration Guidelines and reflect the decisions of the Board of Directors of 19 June and 27 July 2017 as well as the model of organization and corporate governance adopted by the Company.

TABLE OF CONTENTS

In particular, the 2018 remuneration policies take account of: i) the end of the regulatory restrictions concerning the remuneration of executive directors of listed companies subject to government control; ii) the conditions of the 2017-2019 Long-Term Plan approved by the Shareholders Meeting of 13 April 2017 in accordance with Article 114-bis of the Consolidated Law on Financial Intermediation; and iii) the outcome of the comparative studies conducted by considering the total median remuneration of the companies within the Peer Group, appropriately compared to dimensional characteristics of Eni.

Fixed remuneration

Annual fixed remuneration (FR) approved by the Board of Directors on 19 June 2017 for the position of Chief Executive Officer and of General Manager totals €1,600,000 gross, which includes: i) annual remuneration of €600,000 gross for the position of Chief Executive Officer, including annual remuneration of €80,000 gross for the position of member of the Board as approved by the Shareholders Meeting of 13 April 2017; ii) base salary of €1,000,000 gross for the employment relationship as General Manager. This remuneration encompasses any emoluments due for participation in the meetings of the Boards of Directors of other Eni subsidiaries and/or shareholdings.

In his capacity as Senior Manager, the General Manager is also entitled to receive an allowance for travel, in Italy and abroad, in line with the applicable provisions under the relevant national collective bargaining agreement for senior managers of industrial companies and with supplementary company-level agreements.

Variable remuneration

Short-Term Monetary Plan with deferral

The Short-term Incentive Plan with deferral, as approved by the Shareholders’ Meeting of 13 April 2017 under the Remuneration Policy Guidelines and as described in the 2017 Remuneration Report, a portion of the incentive to be paid annually and a portion to be deferred for a three-year period, as described below.

The 2018 Short-Term Monetary Plan with deferral is linked to the achievement of the 2017 objectives approved by the Board of Directors on February 28, 2017.

Achievement of the objectives is assessed net of any exogenous effects (e.g. oil and gas prices or euro/ dollar exchange rates) and in application of a predetermined method of gap analysis as approved by the Compensation Committee.

The 2018 targets approved by the Board on 15 March 2018 for the 2019 short-term variable incentive system with deferral call for maintenance of a structure that is focused on essential milestones in line with the Strategic Plan and balanced in respect of the interests of the various stakeholders in terms of: economic and financial results (25%), operating results and sustainability of the economic performance (25%), environmental sustainability and human capital (25%), efficiency and financial strength (25%). The value of each objective, at target performance level, is aligned with the budgeted value.

In particular, with regard to the objectives of Environmental Sustainability and Human Capital, the use of the Severity Incident Rate (SIR) aims to focus Eni’s commitment on reducing severe incidents, given that Eni has already achieved excellent results in terms of reducing the overall number of injuries.

TABLE OF CONTENTS

More specifically, SIR measures the frequency of total injuries recordable over the number of hours worked and assigns them increasing weights depending on the severity of the incident. In addition, our retention of the CO2 emissions target for operated production confirms Eni's strategic commitment to reducing the emission of greenhouse gases that are connected with climate change and is consistent with the target for 2025 announced to investors.

In line with the general remuneration policy principles, the STI Plan features the characteristics described below.

Each objective is predetermined and measured in accordance with a performance scale of 70 to 150 points (target=100), in relation to the weight assigned to each target (below 70 points, the performance of each target is considered to be zero). For the purposes of the incentive award, the minimum overall performance is 85 points. The total incentive is determined with reference to a minimum (performance=85), target (performance=100) and maximum (performance=150) multiplier, equal respectively to 85%, 100% and 150% to be applied in relation to performance achieved by Eni over the previous year.

Total incentive (TI) is calculated using the following formula:

TI= FR x ITarget x Multiplier

Where "ITarget" is the incentive percentage at target performance level, which is set at 150% of total fixed remuneration for the Chief Executive Officer.

The Plan conditions state that the total incentive is divided into two portions.

1)

a portion paid annually (Iannual) equal to 65% of the total incentive.

Iannual = TIx 65%

The levels of the portion of the incentive payable on a year base, depending on the performance levels achieved, are shown in the table below.

Annual performance	<85	85 threshold	100 target	150 max
Annual incentive (% of Fixed Rem)	0%	83%	98%	146%

2)

a deferred portion equal to 35% of the total incentive, subject to further performance conditions during a three-year vesting period.

The deferred portion payable at the end of the vesting period is determined by multiplying the initial deferred portion by the payment multiplier. The latter is given by the average of the three annual multipliers, each determined during the three-year period in relation to the performance achieved, based on Eni's annual objectives. The multiplier of the deferred portion depends on the performance achieved, with reference to a minimum (performance=85), target (performance=100) and maximum (performance=150) incentive level, equal respectively to 85%, 130% and 230% of total fixed remuneration.

The Deferred Incentive (DI) payable at the end of the three-year deferment period is calculated using the following formula:

DI = TI x 35% x Multiplier

The levels of the payable deferred portion, depending on the performance levels achieved throughout the three-year period, are shown in the table below.

Annual performance	<85	85 threshold	100 target	150 max
Deferred incentive (% of Fixed Rem)	0%	38%	68%	181%

Long-Term share incentives

The Chief Executive Officer participates in the Long-Term Incentive Share Plan 2017-2019, which also applies to Senior Managers, deemed critical for the business, approved by the Shareholders' Meeting on April 13, 2017.

The Plan ensures the following objectives, in line with international best practices:

- strengthening the culture of management of business risk from the perspective of shareholders by incentivizing through share ownership;
- setting a more challenging minimum incentive threshold, positioned at median level;
- further aligning performance conditions with the long-term expectations of shareholders, by reference to:

(i) performance of the Company's Total Shareholder Return over a three-year period compared with that of the Reference Stock Market Index, compared with the same performance of the main international competitors (Peer Group);

(ii) incentivize the capacity to develop industrial assets, measured using the increase in the Net Present Value of hydrocarbon reserves in the medium-long term (in accordance with the assessment method defined by the SEC), measured in relative terms compared with the designated peer group.

The Plan provides for three annual awards starting from 2017, each with a three-year vesting period and is subject to performance conditions, during the three-year vesting period, in accordance with the following parameters and related weightings:

1. The difference between the TSR of Eni Shares and the TSR of the FTSE MIB index of Borsa Italiana, adjusted by the Eni Correlation Coefficient, compared with the equivalent adjusted TSR measure for each company in the Peer Group, as shown in the following formula (50% weight):

TSRA - (TSRI x A,I)

where:

TSRA: TSR of Eni or of one of the companies in the Peer Group;

TSRI: TSR of the Reference Stock Market Index of the company to which TSRA applies;

A,I: Correlation Coefficient between the financial return of the share and the financial return of the reference market (FTSE MIB, S&P 500, FTSE 100, CAC 40, AEX, OBX).

This indicator was introduced in order to neutralize the potential effects of the performance of the respective stock market on the performance of each share. More specifically, this neutralisation is proportionate to the correlation between the stock and the market over the same three-year period by using the correlation coefficient.

2.
Net Present Value of proven reserves (NPV) vs the Peer Group, measured in terms of the annual percentage change, calculating the average annual performance in the three-year period (50% weight).

The reference Peer Group is described in the “Market references and Peer Group” section (Anadarko, Apache, BP, Chevron, Conoco Phillips, ExxonMobil, Marathon Oil, Shell, Statoil and Total).

For the Chief Executive Officer and General Manager, the Plan conditions provide for the annual award of shares for a value equivalent to 150% (Itarget) of total fixed remuneration, using the following formula.

TABLE OF CONTENTS

$$\text{No. of Attributed Shares} = \frac{\text{FR x \% Itarget}}{\text{PriceAttr}}$$

Where the price of the award (PriceAttr) is calculated as the average of daily official prices (source Bloomberg) recorded in the 4 months before the date of the Board of Directors meeting that annually approves the plan rules and the award to the Chief Executive Officer and General Manager.

The granting of shares at the end of the three-year vesting period is determined using a final multiplier to be applied to awarded shares (calculated as the weighted average of the multipliers of each parameter) determined over the vesting period in relation to the position reached in the peer group.

Each multiplier may be between 0 and 180%, with a threshold set at the median level, in accordance with the scale shown below:

Performance Scale – Multiplier

Ranking										
1st	2nd	3rd	4th	5th	6th	7th	8th	9th	10th	11°
Multiplier										
180%	160%	140%	120%	100%	80%	0%	0%	0%	0%	0%
					Median positioning					

Grantable shares are calculated using the following formula:

No. of Granted Shares = No. of Attributed Shares x Multiplier

The threshold, targets and maximum value of Shares (as a percentage of fixed remuneration) grantable to the Chief Executive Officer and General Manager at the end of the vesting period, net of changes in the share price over the same period, are given below.

Weighted average 3-year performance	<26.6	26.6 threshold (*)	100 target	180 max
Value of Shares (% of Fixed Rem)	0%	40%	150%	270%

For executives still in services, the rules of the Plan state that 50% of the shares granted at the end of the vesting period are to remain restricted for one year after the granting date.

Non-monetary Benefits

The Remuneration Policy provides for a life insurance policy and a permanent disability insurance policy covering injury or illness contracted in the workplace or elsewhere, and, as per provisions contained in the national collective bargaining agreement and the supplementary company agreements for Eni senior managers, for enrolment in the supplementary pension plan (FOPDIRE10) and in the supplementary health plan (FISDE11), together with a company car for business and personal use.

Pay Mix

The remuneration package for the Chief Executive Officer and General Manager includes a fixed component, a short-term variable component and a long-term variable component, comprising a short-term incentive deferral and the long-term share incentive valued using the international recognized methodologies for remuneration benchmarks.

(10)
Defined-contribution and individual-capitalization contractual pension fund (www.fopdire.it).

(11)
Fund that reimburses healthcare spending for active or retired senior management and their family members (www.fisde-eni.it).

146

TABLE OF CONTENTS

The pay mix, calculated by considering fixed remuneration as the base, is weighted significantly towards the variable components, with a dominant weighting attributed to the long-term component.

Payments due in the event of termination of office or employment

For the Chief Executive Officer and General Manager, based on a proposal by the Compensation Committee and having heard the opinion of the Board of Statutory Auditors, the Board of Directors resolved on 19 June 2017 to maintain the severance payments in the event of termination of office or of employment established in the 2017 Remuneration Policy Guidelines. These payments are as follows:

1. An indemnity for the administrative relationship in the event of dismissal without cause and/or non-renewal of the office, including in the event of resignation due to a substantive reduction of delegated powers. This indemnity has been set at two years of fixed remuneration for the position, for a total of €1,200,000, in accordance with European Commission Recommendation no. 385 of 30 April 2009;

2. An indemnity in the event of the consensual termination of the employment relationship in relation to termination of the associated administrative position in addition to standard post-employment benefits. This indemnity has been set, taking due account of the provisions of the appropriate national collective bargaining agreement, in accordance with the parameters and policies defined for Eni Managers with strategic responsibilities, equal to two years of annual fixed and variable remuneration for the General Manager position, excluding the Long-Term Share Incentive Plan and with mutual exemption from any obligation of advance notice, without payment of the related indemnity. In reference to criterion 6.C.1, letter g), of the Italian Corporate Governance Code, this indemnity is not due in the following cases: i) dismissal for “just cause” under Article 2119 of the Italian Civil Code; ii) resignation as Chief Executive Officer prior to the expiry of the term in office not justified by a reduction of delegated powers; iii) in the event of death as governed by Article 2122 of the Italian Civil Code; iv) dismissal from the role of Chief Executive Officer for just cause.

With reference to long-term incentives, in the event of early termination for the Chief Executive Officer and General Manager, due to resignation and not justified by a substantial reduction in powers or of termination for cause, all rights to the award and payment of incentives shall lapse. In the event of termination related to expiry of the term on the Board of Directors without renewal[12], the long-term incentives awarded during the term shall vest in accordance with the terms and conditions established by the respective regulations.

In order to safeguard the company’s interests from potential competitive risks related to the considerable international importance of the professional and managerial background of the Chief Executive Officer and General Manager, on 27 July 2017, the Board of Directors, based on the recommendation of the Compensation Committee and having obtained a favourable opinion of the Board of Statutory Auditors, has also resolved to maintain the non-competition agreement in place since 2014, while extending the clause to geographical areas and industries that have taken on greater strategic importance over the last three years.

More specifically, the agreement, which can be activated at the sole discretion of the Board through the exercise of an option right[13], has the following characteristics: i) a validity of 12 months post-termination; ii) restricted markets extended from exploration and production to also include the midstream sector; iii) 18 restricted countries with the addition of Mexico to those that were envisaged during the previous term (Algeria, Angola, Congo, Egypt, Ghana, Indonesia, Iraq, Italy, Kazakhstan, Libya, Mozambique, Nigeria, Norway, Russia, UK, USA, Venezuela); iv) additional confidentiality and non-solicitations restrictions.

Payment for the non-competition agreement provides for maintaining two components calculated on the basis of current remuneration levels and the extension of commitments undertaken: i) a fixed component in the amount of €1,800,000; ii) a variable component to be determined by the Board of Directors, based on a recommendation by the Compensation Committee, in line with the average annual

(12) It should be noted that, under Italian law, directors of joint-stock companies may not be appointed for terms of longer than three financial years, and their terms expire on the date of the meeting of shareholders held to approve the

financial report for the last financial year of their term (Article 2383, second paragraph, of the Italian Civil Code).

(13)
Payment of the option right, for a total of €500,000, was paid in full as reported on page 24 of Eni's 2015 Remuneration Report (Section II, Table 1, note 4 b).

TABLE OF CONTENTS

performance over the previous three years, as follows: for performance below the target, this component will be set to zero; for performance on target, it will be €500,000; and for maximum performance, it will be €1,000,000. The average annual performance shall be calculated on the basis of annual performance achieved under the short-term monetary incentive plan.

2017 POLICIES FOR MANAGERS WITH STRATEGIC RESPONSIBILITIES

For Managers with Strategic Responsibilities, the 2018 Remuneration Policy Guidelines are unchanged on those for 2017, maintaining remuneration plans that are strictly in line with those of the Chief Executive Officer and General Manager, to better guide and align managerial action with the objectives set out in the Company's Strategic Plan, and with the provisions and protections laid down by the national collective bargaining agreement for senior managers.

In particular the new Long-Term Share Incentive Plan and Short-Term Variable Incentive Plan with Deferral – intended for the Chief Executive Officer and General Manager will also apply to Managers with Strategic Responsibilities.

Fixed remuneration

Fixed remuneration is based on the role and responsibilities assigned, taking into consideration a graduated and a generally median to below-median positioning versus national and international executive markets for comparable roles. It may be updated periodically during the annual salary review for all managers.

Given current market comparators and trends, the 2018 Guidelines provide for a selective approach to salary reviews, while maintaining appropriate levels to ensure competitiveness and motivation.

More specifically, the proposed actions will include measures to adjust fixed/one-off remuneration for those in positions that have seen a significant increase in responsibility or scope, and to reflect needs for retention and excellent performance.

In addition, as Eni officers, Managers with Strategic Responsibilities are entitled to receive the allowances due for travel in Italy and abroad, in line with applicable provisions of the relevant national collective bargaining agreement for senior managers and supplementary Company agreements.

Variable incentive plans

Short-term Variable Incentive Plan with deferral

The Short-Term Incentive Plan with deferral, already described for the Chief Executive Officer and General Manager, will be implemented in 2018.

The targets set for Managers with Strategic Responsibilities are consistent with those assigned to the Chief Executive Officer and General Manager, on the basis of the same balancing of stakeholder interests, in addition to relevant individual targets, consistent with the responsibilities of the role played and the provisions of the Company's Strategic Plan. For Managers with Strategic Responsibilities the target incentive levels for the Short-term Incentive Plan with deferral differ depending on the role's level of responsibility and complexity and is limited to a maximum up of 100% of fixed remuneration, with a maximum incentive level payable for the annual and deferred portions of 98% and 121% of fixed remuneration, respectively.

Long-term variable incentive plan

Managers with Strategic Responsibilities participate in the Long-Term Performance Share Plan (LTI) 2017-2019, approved by the Shareholders' Meeting on April 13, 2017.

The Plan is directed at managers who are critical for the business and envisages three annual awards, starting in 2017, with the same performance conditions and characteristics as those described above for the Chief Executive Officer and General Manager.

TABLE OF CONTENTS

For Managers with Strategic Responsibilities, the value of the shares to be awarded each year differs depending upon the level of their role and is limited, to a maximum of 75% of fixed remuneration, with the maximum award corresponding to 135% of fixed remuneration, calculated with reference to the grant price of the shares.

Benefits

In line with national collective bargaining agreement and supplementary Company-level agreements for Eni managers, the Policy Guidelines provide for life and disability insurance cover (due to workplace or other injury or illness), as well as enrolment in the supplementary pension plan (FOPDIRE) and health plan (FISDE), together with a company car for business and personal use, and the possible assignment of housing based on operational and mobility requirements.

Pay Mix

In line with market best practice, as well as the valuation methods used for the Chief Executive Officer and General Manager the average target pay mix of the remuneration package for Managers with strategic responsibilities who are eligible for the Short-Term Monetary Plan with deferral and the Long-Term Performance Share Plan) features a balance between fixed and variable components that is weighted towards medium-long term variable incentives.

Payments due in the event of consensual termination of employment

Managers with Strategic Responsibilities, as well as Eni senior managers, are entitled to the severance benefits for employment termination established by law and applicable national collective bargaining agreement, together with any termination indemnities agreed on an individual basis, in accordance with the criteria established by Eni for cases of early termination, within the limits of the protection envisaged by the applicable national collective bargaining agreement, and consistent with application criterion 6.C.1 lett.g) of the Italian Corporate Governance Code. These criteria take into account the position held, the retirement age and actual age of the manager at the time employment is terminated and the annual remuneration received. For cases of termination that present high competitive risks relating to the criticality of the position held by the Manager, agreements containing non-competition clauses may also be entered into with payments defined in relation to the remuneration received and the scope, duration and effectiveness of the agreement.

COMPENSATION AND OTHER INFORMATION

Implementation of the 2017 remuneration policies

The following is a description of the remuneration decisions taken in 2017 for the Chairman of the Board of Directors, Non-executive Directors, Chief Executive Officer and General Manager, and other Managers with strategic responsibilities, in relation to their time in office.

Implementation of the 2017 remuneration policies for Directors and Managers with strategic responsibilities, as verified by the Remuneration Committee in conjunction with its periodic assessment as provided for in the Corporate Governance Code, was in line with the 2017 Remuneration Policy approved by the Board of Directors on 28 February 2017, taking account of the provisions of the resolutions of the Board of Directors of 13 April 2017 and 19 June 2017 concerning, respectively, remuneration for Non-Executive Directors serving on Board Committees and the remuneration of Directors with delegated powers.

Remuneration paid and or awarded in 2017

In this section, we describe the remuneration paid and/or awarded in 2017 to the Chairman of the Board of Directors, to Non-Executive Directors, to the Chief Executive Officer and General Manager, and to other Managers with strategic responsibilities in accordance with the 2017 Remuneration Policy and in relation to the performance achieved during the period in which they held their respective roles.

TABLE OF CONTENTS

Remuneration paid/awarded in 2017 is shown in Section "Compensation Paid in 2017", on individual basis for the Chairman of the Board of Directors, the Non-Executive Directors, and the Chief Executive Officer and General Manager and in aggregate form for other Managers with strategic responsibilities.

Chairman of the Board of Directors Emma Marcegaglia

Fixed remuneration

The Chairman was paid the following amounts: i) up to 12 April 2017, the prorated amount of fixed remuneration for the role and for the delegated powers, approved respectively by the Shareholders' Meeting on 8 May 2014 and by the Board of Directors on 28 May 2014; ii) since 13 April 2017, the prorated amount of fixed remuneration for the role and for the delegated powers, approved respectively by the Shareholders' Meeting on 13 April 2017 and by the Board of Directors on 19 June 2017.

Non-monetary benefits

The Chairman, in accordance with the resolution of the Board of Directors of 28 May 2014 and 19 June 2017, was granted a life insurance policy and a permanent disability insurance policy covering injury or illness contracted in the workplace or elsewhere.

Non-Executive Directors

The Non-Executive Directors were paid the fixed remuneration approved by the Shareholders' Meeting on 8 May 2014 and confirmed by the Shareholders' Meeting on 13 April 2017 in the amount of €80,000 gross. Non-Executive Directors were also paid the prorated amount of additional remuneration payable for participation on Board Committees, as approved by the Board of Directors on 12 March 2015 for remuneration up to 12 April 2017 and on 13 April 2017 for remuneration subsequent to that date, in line with the 2017 remuneration policies.

Chief Executive Officer and General Manager Claudio Descalzi

Fixed remuneration

The Chief Executive Officer and General Manager was paid the following: i) up to 12 April 2017, the prorated amount of fixed remuneration approved by the Board of Directors on 28 May 2014; ii) since 13 April 2017, the prorated amount of fixed remuneration approved by the Board of Directors on 19 June 2017.

2017 Annual Monetary Incentive

For the 2017 Annual Monetary Incentive Plan, the Chief Executive Officer and General Manager was paid an annual gross variable incentive of €1,674 thousand in 2017 in relation to 2016 performance (124 points) as approved by the Board of Directors on 28 February 2017.

2012-2014 Deferred Monetary Incentive

In 2017 the Chief Executive Officer and General Manager received the Deferred Monetary Incentive awarded in 2014, in his capacity as COO of the E&P Division, in the amount of €465 thousand in relation to the final multiplier verified over the vesting period (123%) as approved by the Board of Directors on 28 February 2017.

2015-2017 Deferred Monetary Incentive

The Chief Executive Officer and General Manager was awarded a gross deferred monetary incentive of €864 thousand in 2017 in relation to the 2016 EBT performance, as approved by the Board of Directors on 28 February 2017.

2014-2016 Long-Term Monetary Incentive

In 2017, the Chief Executive Officer and General Manager was paid the Long-Term Monetary Incentive awarded in 2014 in the amount of €729 thousand, in relation to the final multiplier verified over the vesting period (54%) as approved by the Board of Directors on 19 June 2017.

TABLE OF CONTENTS

2017-2019 Long-Term Equity-based Incentive Plan

In 2017, the Chief Executive Officer and General Manager was awarded 177,968 Eni shares in 2017 as approved by the Board of Directors on 26 October 2017. The number of shares awarded was determined based on the percentage of 150% to be applied to total fixed remuneration and the award price of €13.4856, calculated in accordance with the parameters of the plan.

Non-monetary benefits

In line with the resolutions of the Board of Directors of 28 May 2014 and 19 June 2017, the Chief Executive Officer and General Manager was granted a life insurance policy and a permanent disability insurance policy covering injury or illness contracted in the workplace or elsewhere, as well as, in compliance with the provisions of Italy's national collective bargaining agreement and the supplementary company agreements for Eni senior managers, the enrolment in the supplementary pension plan (FOPDIRE) and supplementary health plan (FISDE), together with a company car for business and personal use.

Managers with strategic responsibilities

Fixed remuneration

In 2017, within the context of the annual salary review process envisaged for all managers, selective adjustments were made to fixed remuneration for current Managers with strategic responsibilities, in cases of promotion to more senior levels, or in line with necessary market-driven adjustments.

2017 Annual Monetary Incentive

In 2017, annual variable incentives were paid to Managers with strategic responsibilities in accordance with the Remuneration Policy and based on performance achieved in 2016. In particular, the incentive is linked to performance against a range of metrics related to business and sustainability objectives (safety, environmental protection, stakeholder relations), as well as relevant individual targets, consistent with the provisions of the Eni Strategic Plan.

2012-2014 Deferred Monetary Incentive Plan

Managers with strategic responsibilities were paid deferred monetary incentives awarded in 2014, on the basis of the final multiplier verified in the vesting period (123%), approved by the Board of Directors on 28 February 2017.

2015-2017 Deferred Monetary Incentive Plan

Managers with strategic responsibilities were granted deferred monetary incentive awards on the basis of the 2016 EBT results, approved by the Board of Directors on 28 February 2017, as proposed by the Remuneration Committee in accordance with the 2017 Remuneration Policy.

2014-2017 Long-Term Monetary Incentive Plan

Managers with strategic responsibilities were paid in 2017 Long-Term monetary incentives awarded in 2014, on the basis of the final multiplier verified in the vesting period (54%), approved by the Board of Directors on 19 June 2017.

2017-2019 Long-Term Share-based Incentive Plan

In accordance with the resolution of the Board of Directors at its meeting of 26 October 2017, managers with strategic responsibilities were granted the first award for the Plan.

Severance indemnity for end-of-office or termination of employment

During 2017, Managers with strategic responsibilities who accepted enhanced voluntary termination offers were paid, in addition to amounts due under legal and contractual obligations, additional amounts defined in line with company policy on early retirement.

Non-monetary benefits

For Managers with strategic responsibilities, in line with provisions in Italy's national collective bargaining agreement and supplementary corporate agreements for Eni managers, the Policy Guidelines provide for enrolment in the supplementary pension plan (FOPDIRE) as well as in the supplementary health plan (FISDE), life and disability insurance cover, together with a company car for business and personal use.

TABLE OF CONTENTS

Incentives vested and payable and/or awardable in 2018

This section describes the incentives vested and payable and/or awardable in 2018 to the Chief Executive Officer and General Manager and to other Managers with strategic responsibilities in relation to the verification of 2017 performance.

Chief Executive Officer and General Manager Claudio Descalzi

2018 Annual Monetary Incentive and Short-Term Incentive Plan with deferral

With reference to the remuneration policy in force during 2017, the following incentives in the period from 1 January to 31 December 2017 vested in favour of the Chief Executive Officer and General Manager:

- 2014-2017 term, up to 12 April 2017. The Board of Directors, on 28 May 2014, approved the procedures and parameters for determining the variable remuneration, corresponding to target and maximum levels of 100% and 130% of fixed remuneration of €1,350,000, determined on the basis of a performance scale of 85-130 points. Therefore, in relation to the performance achieved in 2017 (134 points, reduced to 130 as the maximum applicable score), is payable an annual incentive of €491 thousand, calculated pro rata for the period from 1 January 2017 to 12 April 2017.

- 2017-2020 term, starting 13 April 2017, the Board of Directors, on 19 June 2017, approved the procedures and parameters for determining the variable remuneration of the Chief Executive Officer and General Manager, corresponding to target and maximum levels of 100% and 150% of fixed remuneration of €1,600,000 euro, determined on the basis of a performance scale of 85-150 points and divided into a portion payable in the year and a deferred portion equal, respectively, to 65% and 35% of the total incentive. therefore, in relation to the performance achieved in 2017 (134 points), is payable an annual portion of €1,506 thousand, in addition to a deferred portion awardable of €811 thousand, calculated pro rata for the period from 13 April 2017 to 31 December 2017.

2015-2017 Deferred Monetary Incentive

The incentive awarded in 2015, payable in 2018, vested in favour of the Chief Executive Officer and General Manager in the amount of €1,469 thousand, determined on the basis of the final multiplier verified over the vesting period (170%), as approved by the Board of Directors on 15 March 2018.

Managers with strategic responsibilities

2018 Short-Term Incentive with deferral

The incentives payable/awardable in 2018 based on performance achieved in 2017 vested in favour of the Managers with strategic responsibilities, in the aggregate amounts that will be disclosed in the 2019 Remuneration Report. More specifically, these incentives were related to company performance and a series of business targets, sustainability targets (i.e. safety, environmental protection, relations with stakeholders), and individual targets assigned in relation to the scope of responsibilities of the given role, in line with the provisions of Eni’s Strategic Plan.

2015-2017 Deferred Monetary Incentive

The incentive awarded in 2015, payable in 2018, vested in favour of the Managers with strategic responsibilities, determined on the basis of the final multiplier verified over the vesting period (170%), as approved by the Board of Directors on 15 March 2018. The total aggregate amount of such incentives will be published in 2019 Remuneration Report.

COMPENSATION PAID IN 2017

The table below lists the individual remunerations to the Directors, Statutory Auditors, Chief Executive Officer and General Managers and, in aggregate form, to other Managers with strategic responsibilities. The remunerations received from subsidiaries and/or affiliates, except those waived or paid to the Company, are shown separately. All parties who filled these roles during the period are included, even if they only held office for a fraction of the year.

TABLE OF CONTENTS

In particular:

- the column labelled “Fixed Remuneration” reports fixed remuneration and fixed salary from employment due for the year (on an accrual basis), gross of social security contributions and taxes to be paid by the employee. Details of the compensation are provided in the notes, and any indemnities or payments with reference to the employment relationship are indicated separately;

- the column labelled “Remuneration for participation on Committees” reports (on an accrual basis) the compensation due to Directors for participation in Committees established by the Board. In the notes, compensation for each Committee in which each Director participates is indicated separately;

- the column labelled “Variable non-equity remuneration” under the item “Bonuses and other incentives” shows the incentives paid during the year due to rights vested following the assessment and approval of related performance results by relevant corporate bodies, in accordance with that specified, in greater detail, in the Table “Monetary incentive plans for the Chief Executive Officer and General Manager and other Managers with strategic responsibilities”;

- the column labelled “Profit-sharing” does not show any figures since no profit-sharing mechanisms are in place;

- the column labelled “Benefits in kind” reports (on an accrual and taxability basis) the value of any fringe benefits awarded;

- the column labelled “Other remuneration” reports (on an accrual basis) any other remuneration deriving from other services provided;

- the column labelled “Total” reports the sum of the amounts of all the previous items;

- the column labelled “Fair value of equity compensation” reports the relevant fair value for the year related to the existing stock option plans, estimated in accordance with the international accounting standards that allocate the related cost in the vesting period;

- the column labelled “Severance indemnity for end-of-office or termination of employment” reports indemnities accrued, even if not yet paid, for terminations that occurred during the financial year, or in relation to the end of term in office and/or employment.

TABLE OF CONTENTS

Remuneration paid to Directors, Statutory Auditors, the Chief Executive Officer and General Manager and to other Managers with strategic responsibilities
(amounts in euro thousands)

Name	Note	Position	Period for which the position was held	Expiration of office(*)	Fixed remuneration	Remuneration for participation in Committees	Variable non-equity remuneration		No me be
							Bonuses and other incentives	Profit sharing	
Board of Directors									
Emma Marcegaglia	(1)	Chairman	01.01-12.31	2020	426 (a)				
Claudio Descalzi	(2)	Chief Executive Officer and General Manager	01.01-12.31	2020	1,537 (a)		2,403 (b)		
Andrea Gemma	(3)	Director	01.01-12.31	2020	80 (a)	119 (b)			
Pietro Angelo Guindani	(4)	Director	01.01-12.31	2020	80 (a)	75 (b)			
Karina Litvack	(5)	Director	01.01-12.31	2020	80 (a)	73 (b)			
Alessandro Lorenzi	(6)	Director	01.01-12.31	2020	80 (a)	98 (b)			
Diva Moriani	(7)	Director	01.01-12.31	2020	80 (a)	112 (b)			
Fabrizio Pagani	(8)	Director	01.01-12.31	2020	80 (a)	61 (b)			
Alessandro Profumo	(9)	Director	01.01-04.13	2017	23 (a)	11 (b)			
Domenico Livio Trombone	(10)	Director	04.13-12.31	2020	57 (a)	47 (b)			
Board of Statutory Auditors									
Matteo Caratozzolo	(11)	Chairman	01.01-04.12	2017	23 (a)				
Rosalba Casiraghi	(12)	Chairman	04.13-12.31	2020	57 (a)				
Enrico Maria Bignami	(13)	Statutory auditor	04.13-12.31	2020	50 (a)				
Paola Camagni	(14)	Statutory auditor	01.01-12.31	2020	70 (a)				
Alberto Falini	(15)	Statutory auditor	01.01-04.12	2017	20 (a)				
Marco Lacchini	(16)	Statutory auditor	01.01-04.12	2017	20 (a)				
Andrea Parolini	(17)	Statutory auditor	04.13-12.31	2020	50 (a)				
Marco Seracini	(18)	Statutory auditor	01.01-12.31	2020	70 (a)				

Other Managers with strategic responsibilities(**)	(19)	Remuneration in the company that prepares the Financial Statements	8,794			8,267		2
	Remuneration from subsidiaries and associates		0		0	0		0
	Total		8,794	(a)		8,267	(b)	2
			11,677		596	10,670		2

Note
(*)
The term of office expires with the Shareholders' Meeting approving the Financial Statements for the year end in 31 December 2019.

(**)
Managers who were permanent members of the Company's Management Committee during the year together with the Chief Executive Officer, or who reported directly to the CEO (nineteen managers).

(1)
Emma Marcegaglia — Chairman of the Board of Directors

(a) The amount includes: i) the fixed remuneration of €90 thousand set by the Shareholders' Meeting on 8 May 2014 and confirmed by the Shareholders' Meeting on 13 April 2017; ii) pro quota of fixed remuneration for the delegated powers approved by the Board for the 2014-2017 and 2017-2020 terms, equal to €41.9 and €293.8 thousand, respectively.
(2)
Claudio Descalzi — Chief Executive Officer and General Manager

(a) The amount includes: i) the pro-rata fixed remuneration for the position of Chief Executive Officer for the 2014-2017 and 2017-2020 terms, coming to €155.8 and €430 thousand respectively; ii) the pro-rata fixed remuneration for the position of General Manager for the 2014-2017 and 2017-2020 terms, coming to €194.3 and €757.1 thousand, respectively.
To this amounts are to be added the indemnities due for transfers, in Italy and abroad, in line with the provisions of the relevant national collective labour agreement for senior managers and the Company's complementary agreements for an amount of €17.7 thousand.
(b) The amount includes the annual variable incentive of €1,674 thousand and the Long-Term Monetary Incentive of €729 thousand assigned in 2014 and paid in 2017 in relation to the performance targets achieved during the 2014-2016 vesting period. To this amount is added the Deferred Monetary Incentive assigned in 2014, for the position of COO of the E&P Division, paid in 2017 for an amount of €465 thousand in relation to performance targets achieved during the 2014-2016 vesting period.
(c) The amount includes the taxable value of insurance and welfare coverage, complementary pensions and the car for business and personal use.
(3)
Andrea Gemma — Director

(a) The amount corresponds to the fixed remuneration set by the Shareholders' Meeting on 8 May 2014 and confirmed by the Shareholders' Meeting of 13 April 2017.
(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees for the 2014-2017 and 2017-2020 terms, and in particular €47.2 thousand for participating in the Control and Risk Committee; €35.8 thousand for the Compensation Committee; €5.7 thousand for Sustainability and Scenarios

Committee; €30.1 thousand for the Nomination Committee.
(4)
Pietro Angelo Guindani — Director

(a) The amount corresponds to the fixed remuneration set by the Shareholders' Meeting on 8 May 2014 and confirmed by the Shareholders' Meeting of 13 April 2017.
(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees for the 2014-2017 and 2017-2020 terms, and in particular: €33.6 thousand for participating in the Compensation Committee; €41.5 thousand for the Sustainability and Scenarios Committee.
(5)
Karina Litvack — Director

(a) The amount corresponds to the fixed remuneration set by the Shareholders' Meeting on 8 May 2014 and confirmed by the Shareholders' Meeting of 13 April 2017.
154

TABLE OF CONTENTS

(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees for the 2014-2017 and 2017-2020 terms, and in particular: €36.8 thousand for participating in the Control and Risk Committee; €5.7 thousand for the Compensation Committee; €30.7 thousand for the Sustainability and Scenarios Committee.

(6)
Alessandro Lorenzi — Director

(a) The amount corresponds to the fixed remuneration set by the Shareholders' Meeting on 8 May 2014 and confirmed by the Shareholders' Meeting of 13 April 2017.
(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees for the 2014-2017 and 2017-2020 terms, and in particular: €67.2 thousand for participating in the Control and Risk Committee; €30.8 thousand for the Compensation Committee.

(7)
Diva Moriani — Director

(a) The amount corresponds to the fixed remuneration set by the Shareholders' Meeting on 8 May 2014 and confirmed by the Shareholders' Meeting of 13 April 2017.
(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees for the 2014-2017 and 2017-2020 terms, and in particular: €47.2 thousand for participating in the Control and Risk Committee; €30.8 thousand for the Compensation Committee; €34.3 thousand for the Nomination Committee.

(8)
Fabrizio Pagani — Director

(a) The amount corresponds to the fixed remuneration set by the Shareholders' Meeting on 8 May 2014 and confirmed by the Shareholders' Meeting of 13 April 2017.
(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees for the 2014-2017 and 2017-2020 terms, and in particular: €33.6 thousand for participating in the Sustainability and Scenarios Committee; €27.2 thousand for the Nomination Committee.
(c) The amount corresponds to the pro-rata remuneration for the office of Chairman of the Advisory Board for Oil&Gas.

(9)
Alessandro Profumo — Director

(a) The amount corresponds to the pro-rata annual fixed remuneration until 13 April 2017, set by the Shareholders' Meeting on 8 May 2014.
(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees for the 2014-2017, and in particular: €5.7 thousand for participating in the Sustainability and Scenarios Committee and €5.7 thousand for the Nomination Committee.

(10)
Domenico Livio Trombone — Director

(a) The amount corresponds to the pro-rata annual fixed remuneration set by the Shareholders' Meeting on 13 April 2017.
(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees for the 2017-2020 term, and in particular: €25.1 thousand for participating to the Sustainability and Scenario Commitee; €21,5 thousand for the Nomination Committee.

(11)
Matteo Caratozzolo — Chairman of the Board of the Statutory Auditors

(a) The amount corresponds to the pro-rata annual fixed remuneration until 13 April 2017, set by the Shareholders' Meeting on 8 May 2014.
(b) The amount includes remuneration for serving as Statutory Auditor on the Boards of subsidiaries or associated companies and in particular: €45 thousand as Chairman of the Board of Statutory Auditors of Eni Fuel SpA; €19.5 thousand as Chairman of the Board of Statutory Auditors of Eni Adfin; €45 thousand as Chairman of TTPC SpA.
(12)
Rosalba Casiraghi — Chairman of the Board of the Statutory Auditors

(a) The amount corresponds to the pro-rata annual fixed remuneration since 13 April 2017, set by the Shareholders' Meeting.
(13)
Enrico Maria Bignami — Statutory Auditor

(a) The amount corresponds to the pro-rata annual fixed remuneration set by the Shareholders' Meeting on 13 April 2017.
(14)
Paola Camagni — Statutory Auditor

(a) The amount corresponds to the fixed remuneration set by the Shareholders' Meeting on 8 May 2014 and confirmed by the Shareholders' Meeting of 13 April 2017.
(b) The amount includes remuneration for serving as Statutory Auditor on the Boards of subsidiaries or associated companies and in particular: €19.5 thousand as Chairman of the Board of Statutory Auditors of AGI SpA; €27 thousand as Chairman of the Board of Statutory Auditors of Eni East Africa SpA; €23.3 thousand as Statutory Auditor of Syndial; €30 thousand as Auditor of Eni Angola SpA.
(15)
Alberto Falini — Statutory Auditor

(a) The amount corresponds to the pro-rata annual fixed remuneration until 13 April 2017, set by the Shareholders' Meeting on 8 May 2014.
(b) The amount includes remuneration for serving as Statutory Auditor on the Boards of subsidiaries or associated companies and in particular: €45 thousand as Chairman of the Board of Statutory Auditors of Eni Angola SpA; €18 thousand as Chairman of the Board of Statutory Auditors of Eni Timor Leste SpA; €30 thousand as Auditor for TTPC SpA.
(16)
Marco Lacchini — Statutory Auditor

(a) The amount corresponds to the pro-rata annual fixed remuneration until 13 April 2017, set by the Shareholders' Meeting on 8 May 2014.
(17)
Andrea Parolini — Statutory Auditor

(a) The amount corresponds to the pro-rata annual fixed remuneration set by the Shareholders' Meeting on 13 April 2017.
(18)
Marco Seracini — Statutory Auditor

(a) The amount corresponds to the fixed remuneration set by the Shareholders' Meeting on 8 May 2014 and confirmed by the Shareholders' Meeting of 13 April 2017.
(b) The amount includes remuneration for serving as Statutory Auditor on the Boards of subsidiaries or associated companies and in particular: €27 thousand as Chairman of the Board of Statutory Auditors of LNG Shipping SpA; €27 thousand as Chairman of the Board of Statutory Auditors of Ing. Luigi Conti Vecchi; €30 thousand as Statutory

Auditor of Eni Fuel SpA; €13 thousand as Statutory Auditor of Eni Adfin SpA.
(19)
Other Managers with strategic responsibilities

(a) The amount of €8,794 thousand for Gross Annual Salary is supplemented by the indemnities owed for transfers, in Italy and abroad, in line with the provisions of of the relevant national collective labour agreement and with the Company's additional agreements, as well as other indemnities related to employment for a total of €437 thousand.
(b) The amount includes the payment of €2,946 thousand related to the deferred and long-term monetary incentives assigned in 2014 for performance targets achieved in the 2014-2016 vesting period, as well as the pro-rata amounts of the long-term Incentive Plans (DMI and LTMI), paid upon consensual termination as defined in the respective Plan Regulations. (c) The amount includes the taxable value of insurance and welfare coverage, complementary pensions and the car for business and personal use. (d) Amounts due to for the positions held by Managers with strategic responsibilities in the Supervisory Body established under the Company's Model 231 and the Manager responsible for the preparation of the Company's financial statements.
(e) The amount includes severance payments and early retirement incentives paid in relation to employment termination.

TABLE OF CONTENTS

OTHER INFORMATION

Accrued compensation

Total compensation accrued in the year 2017 pertaining to all the Board members amounted to €14.5 million; it amounted to €0.760 million in the case of the Statutory Auditors. Such amounts include, in addition to each item of emolument reported in the table above, amounts accrued in the year for pension benefits, social security contributions and other elements of the remuneration associated with roles performed, which represent a cost for the Company.

For the year ended December 31, 2017, remuneration of persons in key positions in planning, direction and control functions of Eni Group companies, including executive and non-executive Directors, and other Managers with strategic responsibilities (with reference to all those individuals who, during the course of the 2016 period, filled said roles, even if only for a fraction of the year) amounted to €43 million and was accrued in Eni's Consolidated Financial Statements for the year ended December 31, 2017. The breakdown is as follow:

	2017
	(€ million)
Fees and salaries	25
Post-employment benefits	2
Other long-term benefits	9
Indemnity upon termination of the office	7
	43

The above amounts include salaries, fees for attending meetings, lump-sum amounts paid in lieu of expense reimbursements, stock-based compensation and other deferred incentive bonuses, health and pension contributions and amounts accrued to the reserve for employee termination indemnities, which is used to pay severance pay, as required by Italian law to employees upon termination of employment. The members of the Board of Directors in their capacity as such are not entitled to receive such severance pay.

As of December 31, 2017, the total amount accrued to the reserve for employee termination indemnities with respect to Chief Executive Officer and General Manager, Chief Operating Officers and other Managers with strategic responsibilities (with reference to the employed ones who, during the course of the 2017 period, filled said roles, even if only for a fraction of the year), was €1,483 thousand.

Name		(€ thousand)
Claudio Descalzi	Chief Executive Officer	358
Senior Managers(a)		1,124
		1,483

(a)
No. 18 Managers

Board practices

Corporate Governance

The Corporate Governance structure of Eni follows the Italian traditional management and control model, whereby corporate management is the responsibility of the Board of Directors, which is the core of the organizational system, while supervisory functions are allocated to the Board of Statutory Auditors. The Company's accounts are independently audited by an accredited Audit Firm appointed by the Shareholders' Meeting. Eni complies with the Corporate Governance Code for listed companies (on the Italian Stock Exchange) approved by Italian Corporate Governance Committee (hereinafter "Corporate Governance Code" or "Code"), lastly on July 9, 2015.

The names of Eni's Directors, their positions, the year in which each of them was initially appointed as a Director and their ages are reported in the related table above.

Board of Directors' duties and responsibilities

The Board of Directors has the fullest powers for the ordinary and extraordinary management of the Company in relation to its purpose. In a resolution dated April 13, 2017, the Board, while exclusively reserving to itself the most important strategic, operational and organizational powers, in addition to those that cannot be delegated by law, appointed Claudio Descalzi as CEO and General Manager, entrusting him with the fullest powers for the ordinary and extraordinary management of the Company, with the exception of those powers that cannot be delegated under current law and those retained by the Board.

In the same resolution, the Board of Directors resolved to confirm to the Chairman a major role in internal controls and not operational functions. In particular, with reference to Internal Audit, the Board of Directors resolved that, in accordance with the Corporate Governance Code, the Head of the Internal Audit Department reports to the Board, and on its behalf, to the Chairman, without prejudice to its functional reporting to the Control and Risk Committee and the Chief Executive Officer, as the director in charge of the internal control and risk management system. The Chairman is also involved in the appointment of the primary Eni officers in charge of internal controls and risk management, as well as in approving internal rules governing the Internal Audit process. In addition, the Chairman carries out her statutory functions as legal representative, managing institutional relationships in Italy, together with the Chief Executive Officer.

Finally, the Board of Directors entrusted the Board Secretary with the role of Corporate Governance Counsel, who reports hierarchically and functionally to the Board and, on its behalf, to the Chairman. He lends assistance and independent legal advice to the Board and the Directors and periodically presents to the Board of Directors a report on the functioning of Eni's Corporate Governance system.

On April 13, 2017, the Board reserved to itself the strategic, operational and organizational powers briefly described below:

- defines the system and rules of Corporate Governance for the Company and the Group;
- establishes the Board's internal committees, appoints their members and chairmen, determines their duties and compensation, and approves their procedural rules and annual budgets;
- expresses the general criteria for determining the maximum number of offices that a Company Director may hold in other companies;
- delegates and revokes the powers of the CEO and the Chairman, establishing the limits and procedures for exercising those powers and determining the compensation associated with these duties;
- establishes the basic structure of the organizational, administrative and accounting arrangements of the Company (including the internal control and risk management system), of its strategically important subsidiaries and of the Group as a whole. It evaluates the adequacy of these arrangements;
- establishes the guidelines for the internal control and risk management system, so that the main risks facing the Company and its subsidiaries are correctly identified and adequately measured, managed and monitored, determining the degree of compatibility of such risks with the management of the Company in a manner consistent with its stated strategic objectives. It sets the financial risk limits of the Company. It also examines the main business risks, which are identified taking into account the characteristics of the activities carried out by the Company and its subsidiaries

and which are reported by the Chief Executive Officer at least quarterly. Moreover, it evaluates, every six months, the adequacy of the internal control and risk management system with respect to the characteristics of the Company and its risk profile, as well as the system's effectiveness;

- approves at least annually the Audit Plan drawn up by the Senior Executive Vice President of the Internal Audit Department. It also evaluates the findings contained in the recommendation letter, if any, of the Audit Firm and in its statement on the key issues that arose during the statutory audit;

- defines the strategic guidelines and objectives of the Company and the Group, including sustainability policies. It examines and approves the budgets and strategic, industrial and financial

TABLE OF CONTENTS

plans of the Group, periodically monitoring their implementation, as well as agreements of a strategic nature for the Company. It examines and approves the plan for the Company's non-profit activities and approves operations not included in the plan whose cost exceeds €500,000;

- examines and approves the annual financial report (which includes Eni's draft Financial Statements and the Consolidated Financial Statements) and the semi-annual and quarterly financial reports required by applicable law. It reviews and approves the Sustainability Reporting when it is not already contained in the financial report;

- receives reports from Directors with delegated powers at Board meetings, or on at least a bi-monthly basis, on the actions taken in exercising their delegated powers;

- receives a report from the Board's internal committees on at least a semi-annual basis;

- assesses general developments in the operations of the Company and of the Group, paying particular attention to conflicts of interest and comparing the results with budget forecasts;

- evaluates and approves transactions of the Company and its subsidiaries with related parties provided for in the procedure approved by the Board14, as well as transactions in which the CEO has an interest;

- evaluates and approves any transaction executed by the Company and its subsidiaries that has a significant strategic, economic, financial or asset impact on the Company;

- appoints and removes the Chief Operating Officers, the Officer in charge of preparing financial reports, the Senior Executive Vice President of the Internal Audit Department and the Eni Watch Structure. It ensures the designation of a manager responsible for shareholder relations;

- examines and approves the Remuneration Report and, in particular, the Remuneration Policy for Directors and Managers with strategic responsibilities to be presented to the Shareholders' Meeting. It also defines the criteria for remunerating the senior executives of the Company and of the Group and takes steps to implement compensation plans based on shares or other financial instruments approved by the Shareholders' Meeting;

- resolves on the exercise of voting rights and on the appointment of members of corporate bodies of the strategically important subsidiaries;

- formulates the proposals to present to the Shareholders' Meeting; and

- examines and resolves on other issues that Directors with delegated powers believe should be presented to the Board due to their particular importance or sensitivity.

In accordance with Article 23.2 of the By-laws, the Board also resolves on mergers and proportional spin-offs of companies in which Eni's shareholding is at least 90%; the establishment and closing of branches; and the amendment of the By-laws to comply with the provisions of law.

In accordance with the By-laws, the Chairman and the Chief Executive Officer retain representative powers for the Company.

Directors' independence

On the basis of statements made by the Directors and other information available to the Company, during its meeting of April 13, 2017 and, after an investigation by the Nomination Committee, at its meeting of February 15, 2018, the Board of Directors determined that Chairman Marcegaglia and Directors Gemma, Guindani, Litvack, Lorenzi, Moriani and Trombone satisfy the independence requirements established by law, as referenced in Eni's By-laws. Furthermore, Directors Gemma, Guindani, Litvack, Lorenzi, Moriani and Trombone have been deemed independent by the Board pursuant to the criteria and parameters recommended by the Corporate Governance Code. Chairman Marcegaglia, in compliance with the Corporate Governance Code, could not be deemed independent as she is a significant representative of the Company.

At the last assessment, the Board of Directors also evaluated that the commercial relationships between Eni and Vodafone Italy, a company of which Director Guindani is a significant representative, and between Eni and Selecta SpA and between Eni and companies of KME Group, companies subject to significant influence by Director Moriani, are not significant for the purpose of assessing the independence of these Directors, having regard to the nature and the amounts of these relationships. The relationships

(14)

The Board of Directors, on November 18, 2010, approved the Management System Guideline (MSG) "Transactions involving interests of Directors and Statutory Auditors and transactions with related parties", which has been applied since January 1, 2011, to ensure transparency and substantial and procedural fairness of transactions with related parties. The Board modified this MSG on January 19, 2012 and, lastly, on April 4, 2017.

TABLE OF CONTENTS

were evaluated on the basis of statements made by the Directors and other information available to the Company, and taking into account that – due to the nature of the companies mentioned above – transactions between these companies and Eni were subject to related parties' transactions regulation and to reporting to the Company's body.

The Board of Statutory Auditors ascertained that the Board of Directors correctly applied the assessment criteria and procedures for evaluating the independence of its members.

The independence criteria may not be equivalent to the independence criteria set forth in the NYSE listing standards applicable to a U.S. domestic company.

Board Committees

The Board of Directors has established four internal Committees to provide it with recommendations and advice: (a) the Control and Risk Committee; (b) the Remuneration Committee; (c) the Nomination Committee; and (d) the Sustainability and Scenarios Committee. Committees under letters (a), (b) and (c) are recommended by the Corporate Governance Code. The composition, duties and operational procedures of these committees are governed by their own rules, which are approved by the Board, in compliance with the criteria outlined in the Corporate Governance Code.

The Committees recommended by the Corporate Governance Code are composed of no fewer than three members and, in any case, less than a majority of members of the Board. The composition is described in the following sections pertaining each Committee.

All Board Committees report to the Board of Directors, at least once every six months, on activities carried out. In addition, the Chairmen of the Committees report to the Board at each meeting of the Board on the key issues examined by the Committees in their previous meetings.

In the exercise of their functions, the Committees have the right to access any information and Company functions necessary to perform their duties. They are also provided with adequate financial resources, in accordance with the terms established by the Board of Directors, and can avail themselves of external advisers.

The Chairman of the Board of Statutory Auditors or a Statutory Auditor designated by him, participates in Control and Risk Committee and Remuneration Committee meetings and may participate in other Committees' meetings. Furthermore, Committees may invite other persons to attend the meetings in relation to individual items on the agenda.

The CEO and the Chairman may attend the meetings of the Nomination Committee and of the Sustainability and Scenarios Committee. Furthermore, they may attend Control and Risk Committee meetings, unless matters relating to them are discussed. Finally, they may attend Remuneration Committee meetings upon the invitation of its Chairman, except when the meetings are examining proposals regarding their remuneration15.

The Board Secretary and Corporate Governance Counsel coordinates the secretaries of the Board Committees, receiving at this end information on the calendar of the meetings and the items in the Committees' agendas, the notices of the meetings, as well as their signed minutes.

Minutes of all Committee meetings are usually drafted by their respective secretaries. The current members of the Control and Risk Committee, Remuneration Committee, Nomination Committee and Sustainability and Scenarios Committee were appointed by the Board of Directors on April 13, 2017.

Remuneration Committee

Members: Andrea Gemma (Chairman), Pietro A. Guindani, Alessandro Lorenzi, Diva Moriani.

The Remuneration Committee is made up of non-executive, independent Directors. All the members possess adequate professional requirements and expertise for carrying out the duties assigned to the Committee. The Committee's rules require that at least one of its members possess adequate knowledge and experience of financial matters or remuneration policies, as assessed by the Board at the time of his or her appointment.

(15)

Rules of the Remuneration Committee establish that "no Director and, in particular, no Director with delegated powers may take part in meetings of the Committee during which Board proposals regarding his remuneration are being discussed, unless are deemed proposals on all the members of the Committees established within the Board of Directors."

159

TABLE OF CONTENTS

Established by the Board of Directors for the first time in 1996, in accordance with the By-laws, the Committee provides recommendations and advice to the Board of Directors. More specifically, the Committee:

a)
submits the Remuneration Report and in particular the Remuneration Policy for Directors and Managers with strategic responsibilities to the Board of Directors for approval, prior to its presentation at the Shareholders' Meeting called to approve the year's financial statements, in accordance with the time limits set by applicable law;

b)
periodically evaluates the adequacy, overall consistency and effective implementation of the Policy, formulating proposals, as appropriate, for approval by the Board of Directors;

c)
presents proposals for the remuneration of the Chairman and the Chief Executive Officer, including the various components of compensation and non monetary benefits;

d)
presents proposals for the remuneration of Board Committee members;

e)
having examined the Chief Executive Officer's indication, proposes general criteria for the compensation of Managers with strategic responsibilities, the annual and Long-Term incentive plans, including equity-based ones, sets performance objectives and assesses performance against them, in connection with the determination of the variable portion of the remuneration for Directors with delegated powers and with the implementation of the approved incentive plans;

f)
monitors execution of decisions taken by the Board;

g)
reports at the first available meeting of the Board of Directors through the Committee Chairman on the most significant issues addressed by the Committee during the meetings. It also reports to the Board on its activities at least every six months and no later than the time limit for the approval of the Annual Report and the Interim Report at 30 June, at the Board meeting designated by the Chairman of the Board of Directors.

Furthermore, in exercising its functions, the Committee may issue opinions as required by Company procedures in relation to operations with related parties, in accordance with specified procedures.

During 2017, the Remuneration Committee met a total of ten times, with an average attendance of 98% of its members and an average duration of 2 hours and 35 minutes. At least one member of the Board of Statutory Auditors participated in each meeting as well as, following the renewal of corporate bodies, the Chairman of the Board of Auditors.

Earlier in the year, the Committee focused its activities in particular on the following topics:

i.
review, with the assistance from leading law firms, of relevant updates to legal and regulatory requirements governing Directors or Managers severance arrangements under Italy's national collective bargaining regime (CCNL);

ii.
periodic evaluation of Remuneration Policy, as implemented in 2016, also with a view to developing new Policy proposals for 2017, which provided for the introduction of a new and generally simplified variable incentive system, as discussed in greater detail in the 2017 Remuneration Report;

iii.
verification of the Company's 2016 results for the purpose of implementing the Short- and Long-Term variable incentive plans, using a predetermined gap analysis method approved by the Committee in order to neutralise the positive or negative impact of exogenous factors and enable the objective assessment of the performance achieved;

iv.
definition of 2017 performance targets relevant to the variable incentive plans, with the introduction in the new Short-Term Incentive Plan with deferral, of the new "Severity Incident Rate" metric, which measures both the frequency and severity of injuries, replacing the previous metric, the Total Recordable Incident Rate (TRIR);

v.
definition of proposals for the implementation of the Deferred Monetary Incentive Plan for the Chief Executive Officer and General Manager, as well as for other senior executives;

vi.
definition of proposals for the new Short-Term and Long-Term Share Incentive Plans 2017-2019. The procedures and characteristics of the LTI Plan are described in the Information Document examined for subsequent approval by the Shareholders' Meeting, in accordance with Art. 114-bis of the Consolidated Law on Financial Intermediation, and in the 2017 Remuneration Report;

vii.
review of the 2017 Eni Remuneration report;

viii.
review of the outcome of the meetings conducted with main institutional investors, before the 2017 Shareholders' Meeting, in order to maximize shareholder consensus on the 2017 Remuneration Policy, as well as develop voting projections with the support of an international consultant.

TABLE OF CONTENTS

ix.
definition, following the appointment of the corporate bodies, of the proposals for the remuneration of the Directors with delegated powers (Chairman – Chief Executive Officer and General Manager) for the 2017-2020 term, in particular with regard to the fixed component, consistently with the Eni 2017 Remuneration Policy and with the conditions of the 2017-2019 Long-Term Incentive Plan, approved by the Shareholders' Meeting of April 13, 2017.

As regards further important activities carried out during the second half of the year, the Committee:

i.
examined the 2017 Shareholders' Meeting vote results, with regard to the Eni Remuneration Report as well as to the 2017-2019 Long-Term Share Incentive Plan, compared to the results of the main Italian and European listed companies and of the Peer Group.

ii.
finalised the proposal (2017 grant) for the implementation of the 2017-2019 Long-Term Share Incentive Plan for the Chief Executive Officer and General Manager and for Mangers with strategic responsibilities;

iii.
review of the outcome of the first cycle of engagement conducted, after the 2017 Shareholders' Meeting, with various Eni institutional investors and leading proxy advisors, as well as additional planned activities in the run up to the 2018 Shareholders' Meeting, to enable the broadest possible understanding and sharing of the Policy;

iv.
started the review of 2018 Remuneration Policy Guidelines, with the support of the competent Company functions, in the light of the monitoring conducted of the developments in the regulatory framework and in market standards of reporting on remuneration issues.

The composition and appointment, as well as the duties and operational procedures, of the Committee are governed by the Rules approved by the Board of Directors, available to the public on the Company's website (https://www.eni.com/docs/en_IT/enicom/company/governance/rules-of-the-remuneration-committee.pdf).

Control and Risk Committee

Members: Alessandro Lorenzi (Chairman), Andrea Gemma, Karina Litvack and Diva Moriani16.

The Control and Risk Committee is entrusted with supporting, on the basis of an appropriate control process, the Board of Directors in evaluating and making decisions concerning the internal control and risk management system and in approving the periodical financial reports. It is entirely made up of non-executive and independent Directors17 who possess the necessary expertise consistent with the duties they are required to perform18.

In particular, at their appointment, the Directors Lorenzi, Litvack and Moriani were identified by the Board as members with "adequate experience in the area of accounting and finance or risk management", as recommended by the Corporate Governance Code.

The Committee advises the Board of Directors and specifically issues its prior opinion: a) and drafts recommendations concerning the guidelines for the internal control and risk management system so that the main risks faced by the Company and its subsidiaries can be correctly identified and appropriately measured, managed and monitored and also supports the Board in determining the degree of compatibility of such risks with the management of the Company in a manner consistent with its stated strategic objectives; b) on the assessment, performed by the Board of Directors, on the main company risks, identified taking into account the characteristics of the activities carried out by the company or its subsidiaries; c) on the evaluation, performed at least every six months, of the adequacy of the internal control and risk management system, taking account of the characteristics of the Company and its risk profile, as well as its effectiveness. To this end, at least once every six months it reports to the Board of Directors, on the occasion of the approval of the annual and semi-annual financial reports, on its activities and on the adequacy of the internal control and risk management system at the meeting of the Board of Directors indicated by the Chairman of the Board of Directors; d) on the approval, at least once a year, of

16
During 2017 the composition of the Control and Risk Committee was: i) Lorenzi, Gemma, Moriani until the Shareholders' Meeting of April 13, and ii) Lorenzi, Gemma, Litvack and Moriani, after April 13, 2017.

17
In accordance with the rules of the Control and Risk Committee, the Committee is made up of three to four non-executive Directors, all of whom are independent. Alternatively, the Committee may be made up of non-executive Directors, a majority of whom shall be independent. In the latter case, the Chairman of the Committee shall be chosen from among the independent Directors. In any case, the number of members shall be fewer than the number representing a majority on the Board.

18
The Governance system put in place by Eni establishes that at least two members of the Committee– and not just one as recommend by the Corporate Governance Code for listed companies – must possess adequate experience in financial and accounting matters or in risk management, as assessed by the Board of Directors at the time of their appointment.

TABLE OF CONTENTS

the Audit Plan prepared by the Senior Executive Vice President of the Internal Audit Department; e) on the description, in the annual Corporate Governance Report, of the main features of the internal control and risk management system, and how the different subjects involved therein are coordinated, providing its evaluation of the overall adequacy of the system itself; and f) on the evaluation of the findings reported by the Audit Firm in any recommendations letter it may issue and in the latter's report on the main issues arising during the audit.

The Committee furthermore: a) issues opinions to the Board of Directors on specific aspects concerning the identification of the main risks faced by the Company; b) examines and issues an opinion on the adoption and amendment of the rules on the transparency and the substantive and procedural fairness of transactions with related parties and those in which a Director or Statutory Auditor holds a personal interest or an interest on behalf of a third party, while performing additional duties assigned it by the Board of Directors, including examining and issuing an evaluation on specific types of transactions, except for those relating to compensation; and c) gives an opinion on the fundamental guidelines of the Regulatory System, the regulatory instruments to be approved by the Board of Directors, their amendment or update and, upon request by the CEO, on specific aspects in relation to the instruments implementing the fundamental guidelines.

In addition, the Committee, in assisting the Board of Directors: a) evaluates, together with the Officer in charge of preparing financial reports and after having consulted the Audit Firm and the Board of Statutory Auditors, the proper application of accounting standards and their consistency in preparing the Consolidated Financial Statements, prior to their approval by the Board of Directors; b) examines and evaluates Reports prepared by the CFO/Officer in charge of preparing financial reports through which it shall give its opinion to the Board of Directors on the appropriateness of the powers and resources assigned to the Officer himself and on the proper application of accounting and administrative procedures, enabling the Board to exercise its legally mandated supervision tasks; c) at the request of the Board, it supports, with adequate preliminary activities, the Board of Directors' assessments and resolutions on the management of risks arising from detrimental facts of which the Board may have become aware and d) monitors the independence, adequacy, efficiency and effectiveness of the Internal Audit Department and oversees its activities with respect to the duties of the Board of Directors in this area, and on its behalf, of the Chairman, ensuring that they are performed with the necessary independence and required level of objectivity, competence and professional diligence, in accordance with the Code of Ethics of Eni SpA and international standards.

A favorable opinion of the Committee is required for the approval to the Board on proposals by the Chairman in agreement with the CEO concerning the appointment, the removal and, consistent with the Company's policies, the structure of the fixed and variable compensation of the Senior Executive Vice President of the Internal Audit Department, as well as on the adequacy of the resources provided to the latter to perform his duties.

The Committee also: a) evaluates, on the occasion of his appointment, whether the Senior Executive Vice President of the Internal Audit Department meets the integrity, professionalism, competence and experience requirements and, on an annual basis, assesses their fulfilment; b) examines the results of the audit activities performed by the Internal Audit Department; c) examines the periodic reports prepared by the Senior Executive Vice President of the Internal Audit Department as to whether it contains adequate information on the activities carried out, on the manner in which risk management is conducted and on compliance with risk containment plans, as well as assesses the appropriateness of the internal control and risk management system. It also examines the reports prepared promptly by the Senior Executive Vice President of the Internal Audit Department on events of particular importance; and d) examines the information received from the Senior Executive Vice President of the Internal Audit Department and promptly reports its assessment to the Board of Directors in the case of: (i) significant deficiencies in the system for preventing irregularities and fraudulent acts, and irregularities or fraudulent acts committed by management personnel or by employees that perform important roles in the design or operation of the internal control and risk management system; and (ii) circumstances that may affect the maintenance of the independence of the Internal Audit Department and of auditing activities.

The Committee may also ask the Internal Audit Department to perform audits on specific operational areas, providing simultaneous notice to the Chairman of the Board of Statutory Auditors. The Committee also examines and assesses: a) communications and information received from the Board of Statutory

TABLE OF CONTENTS

Auditors and its members regarding the internal control and risk management system, including those concerning the findings of enquiries conducted by the Internal Audit Department in connection with reports received (whistleblowing), including anonymous reports; b) half yearly reports issued by Eni's Watch Structure, including in its capacity as Guarantor of the Code of Ethics, as well as the timely updates provided by the Structure, after the updates have been given to the Chairman of the Board and to the CEO, about any particular material or significant situation detected in the performance of its duty; c) information on the internal control and risk management system, including that provided in the course of periodic meetings with the competent Company structures; and d) enquiries and reviews concerning the internal control and risk management system carried out by third parties.

Furthermore, the Committee oversees the activities of the Legal Affairs Department in case of judicial inquiries, carried out in Italy and/or abroad, in relation to which the CEO and/or the Chairman of the Company and/or a member of the Board of Directors and/or an Executive reporting directly to the CEO, even if no longer in office, have received a notice of investigation for crimes against the Public Administration and/or corporate crimes and/or environmental crimes, related to their mandate and their scope of responsibility.

The composition and appointment, as well as duties and operational procedures of the Committee, are governed by rules approved by the Board of Directors lastly on May 9, 2017 available to the public at the Company's website.

Nomination Committee

Members: Diva Moriani (Chairman), Andrea Gemma, Fabrizio Pagani and Domenico Livio Trombone.

The Nomination Committee is made up of non-executive Directors, a majority of whom are independent.

The Committee provides recommendations and a