ENI SPA
Form 20-F
April 05, 2019

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, 2018

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

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Certain disclosures contained herein including, without limitation, certain 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’, va of such words, and similar expressions are intended to identify such forward-looking statements. These forward-looking statements are only predictions and are subject to risks, uncertainties, and assumptions that are difficult to predict because they relate to events and depend on circumstances that will occur in the future. Therefore, Eni’s actual results may differ materially and adversely from those expressed or implied in any forward-looking statements. Factors that might cause or contribute to such differences include, but are not limited to, those discussed in this Annual Report on Form 20-F under the section entitled “Risk factors” and elsewhere. Any forward-looking statements made by or on behalf of Eni speak only as of the date they are made. Eni does not undertake to update forward-looking statements to reflect any changes in Eni’s expectations with regard thereto or any changes in events, conditions or circumstances on which any such statement is based. The reader should, however, consult any further disclosures Eni may make in documents it files with the SEC.

CERTAIN DEFINED TERMS

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

PRESENTATION OF FINANCIAL AND OTHER INFORMATION

The Consolidated Financial Statements of Eni, included in this Annual Report, have been prepared in accordance with 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 which are managed 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.

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GLOSSARY

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

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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.
Mineral Storage	According to Legislative Decree No. 164/2000, these are volumes required for allowing optimal operation of natural gas fields in Italy for technical and economic reasons. The purpose is to ensure production flexibility as required by long-term purchase contracts as well as to cover technical risks associated with production.
Modulation Storage	According to Legislative Decree No. 164/2000, these are volumes required for meeting hourly, daily and seasonal swings in demand.
Natural gas liquids (NGL)	Liquid or liquefied hydrocarbons recovered from natural gas through separation equipment or natural gas treatment plants. Propane, normal-butane and isobutane, isopentane and pentane plus, that were previously defined as natural gasoline, are natural gas liquids.

Network Code	A code containing norms and regulations for access to, management and operation of natural gas pipelines.

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Over/Under lifting	Agreements stipulated between partners which regulate the right of each to its share in the production for a set period of time. Amounts lifted by a partner different from the agreed amounts determine temporary Over/Under lifting situations.
Possible reserves	Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.
Probable reserves	Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.
Primary balanced refining capacity	Maximum amount of feedstock that can be processed in a refinery to obtain finished products measured in BBL/d.
Production Sharing Agreement (PSA)	Contract regulates 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.

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Reserve replacement ratio	Measure of the reserves produced replaced by proved reserves. Indicates the company's ability to add new reserves through exploration and purchase of property. A rate higher than 100% indicates that more reserves were added than produced in the period. The ratio should be averaged on a three-year period in order to reduce the distortion deriving from the purchase of proved property, the revision of previous estimates, enhanced recovery, improvement in recovery rates and changes in the amount of reserves – in PSAs – due to changes in international oil prices.
Ship-or-pay	Clause included in natural gas transportation contracts according to which the customer is requested to pay for the transportation of gas whether or not the gas is actually transported.
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.

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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	= barrel
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	= 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)

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PART I

Item 1. IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISORS

NOT APPLICABLE

Item 2. OFFER STATISTICS AND EXPECTED TIMETABLE

NOT APPLICABLE

Item 3. KEY INFORMATION

Selected Financial Information

The Consolidated Financial Statements of Eni have been prepared in accordance with IFRS 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, 2014, 2015, 2016, 2017 and 2018. Eni has adopted IFRS 9 'Financial Instruments' and IFRS 15 'Revenue from Contracts with Customers' with effect from 1 January 2018. Information on the implementation of new accounting standards is included in the Financial statements – Note 3 Changes in accounting policies. As permitted by IFRS 9 comparatives have not been restated; while with regard to IFRS 16, Eni has elected to apply the 'modified retrospective' approach to transition permitted by IFRS 15 under which comparative financial information is not restated. The adoption of the new standards did not have a material effect on the group's financial statements as at January 1, 2018. In 2015, the business segment Engineering & Construction (E&C), operated by Eni's former subsidiary Saipem, was classified as discontinued operations based on the guidelines of IFRS 5. On January 26, 2016 Eni divested part of its interest in Saipem; this transaction triggered the loss of control on the former subsidiary. The retained interest in Saipem (31%) was classified as an investment in a joint venture, accounted for under the equity method. Also in the financial data for 2014 the E&C segment is presented as discontinued operations. 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,				
	2018	2017	2016	2015	2014
	(€ million except data per share and per ADR)				
CONSOLIDATED PROFIT STATEMENT DATA					
Net sales from continuing operations	75,822	66,919	55,762	72,286	98,218
Operating profit (loss) by segment from continuing operations					
Exploration & Production	10,214	7,651	2,567	(959)	10,727
Gas & Power	629	75	(391)	(1,258)	64
Refining & Marketing and Chemicals	(380)	981	723	(1,567)	(2,811)
Corporate and Other activities	(691)	(668)	(681)	(497)	(518)
Impact of unrealized intragroup profit elimination and other consolidation adjustments(1)	211	(27)	(61)	1,205	1,503
Operating profit (loss) from continuing operations	9,983	8,012	2,157	(3,076)	8,965
Net profit (loss) attributable to Eni from continuing operations	4,126	3,374	(1,051)	(7,952)	1,720
Net profit (loss) attributable to Eni from discontinued operations			(413)	(826)	(413)
Net profit (loss) attributable to Eni	4,126	3,374	(1,464)	(8,778)	1,307
Data per ordinary share (euro)(2)					
Operating profit (loss):					
– basic	2.77	2.22	0.60	(0.85)	2.48
– diluted	2.77	2.22	0.60	(0.85)	2.48

Net profit (loss) attributable to Eni basic and diluted from continuing operations	1.15	0.94	(0.29)	(2.21)	0.48
Net profit (loss) attributable to Eni basic and diluted from discontinued operations	0.00	0.00	(0.12)	(0.23)	(0.12)
Net profit (loss) attributable to Eni basic and diluted	1.15	0.94	(0.41)	(2.44)	0.36
Data per ADR ($)(2)(3)					
Operating profit (loss):					
– basic	6.55	5.03	1.33	(1.90)	6.59
– diluted	6.55	5.03	1.33	(1.90)	6.59
Net profit (loss) attributable to Eni basic and diluted from continuing operations	2.72	2.12	(0.65)	(4.90)	1.27
Net profit (loss) attributable to Eni basic and diluted from discontinued operations	0.00	0.00	(0.25)	(0.51)	(0.31)
Net profit (loss) attributable to Eni basic and diluted	2.72	2.12	(0.90)	(5.41)	0.96

(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.

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(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 2018 is based on the proposal of Eni's management which is submitted to approval at the Annual General Shareholders' Meeting scheduled on May 14, 2019.

(3)
Eni's financial statements are stated in euro. The translations of certain euro amounts into U.S. dollars are included solely for the convenience of the reader. The convenient translations should not be construed as representations that the amounts in euro have been, could have been, or could in the future be, converted into U.S. dollars at this or any other rate of exchange. Data per ADR, with the exception of dividends, were translated at the EUR/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 2014 through 2017 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 2018 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 (€0.84 per ADR) at the Noon Buying Rate recorded on the payment date on September 26, 2018, while the balance of €0.82 per ADR was translated at the Noon Buying Rate as recorded on December 31, 2018. The balance dividend for 2018 once the full-year dividend is approved by the Annual General Shareholders' Meeting is payable on May 22, 2019 to holders of Eni shares, being the ex-dividend date May 20, 2019 while ADRs holders will be paid on June 06, 2019.

	As of December 31,				
	2018	2017	2016	2015	2014
	(€ million except data per share and per ADR)				
CONSOLIDATED BALANCE SHEET DATA					
Total assets	118,373	114,928	124,545	139,001	150,366
Short-term and long-term debt	25,865	24,707	27,239	27,793	25,891
Capital stock issued	4,005	4,005	4,005	4,005	4,005
Non-controlling interest	57	49	49	1,916	2,455
Shareholders' equity – Eni share	51,016	48,030	53,037	55,493	63,186
Capital expenditures from continuing operations	9,119	8,681	9,180	10,741	11,178
Weighted average number of ordinary shares outstanding (fully diluted – shares million)	3,601	3,601	3,601	3,601	3,610
Dividend per share (euro)(1)	0.83	0.80	0.80	0.80	1.12
Dividend per ADR ($)(1)(2)	1.96	1.81	1.77	1.77	2.65

(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 2018 is based on the proposal of Eni's management which is submitted to approval at the Annual General Shareholders' Meeting scheduled on May 14, 2019.

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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 2017 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 2018 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 (€0.84 per ADR) at the Noon Buying Rate recorded on the payment date on September 26, 2018, while the balance of €0.82 per ADR was translated at the Noon Buying Rate as recorded on December 31, 2018. The balance dividend for 2018 once the full-year dividend is approved by the Annual General Shareholders' Meeting is payable on May 22, 2019 to holders of Eni shares, being the ex-dividend date May 20, 2019 while ADRs holders will be paid on June 06, 2019

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Selected Operating Information

The tables below set forth selected operating information with respect to Eni's proved reserves, developed and undeveloped, of crude oil (including condensates and natural gas liquids) and natural gas, as well as other data as of and for the years ended December 31, 2014, 2015, 2016, 2017 and 2018.

	Year ended December 31,				
	2018	2017	2016	2015	2014
Proved reserves of liquids of consolidated subsidiaries at period end (mmBBL)	3,183	3,262	3,230	3,372	3,077
of which developed	2,208	2,220	2,190	2,100	1,847
Proved reserves of liquids of equity-accounted entities at period end (mmBBL)	357	160	168	187	149
of which developed	205	43	43	48	46
Proved reserves of natural gas of consolidated subsidiaries at period end (BCF)	17,324	17,290	18,462	14,302	14,808
of which developed	11,203	9,535	9,244	8,899	8,342
Proved reserves of natural gas of equity-accounted entities at period end (BCF)	2,400	2,182	3,871	3,993	3,737
of which developed	2,063	1,916	1,905	1,402	120
Proved reserves of hydrocarbons of consolidated subsidiaries in mmBOE at period end	6,356	6,430	6,613	5,975	5,772
of which developed	4,261	3,967	3,884	3,720	3,366
Proved reserves of hydrocarbons of equity-accounted entities in mmBOE at period end	797	560	877	915	830
of which developed	583	394	391	303	67
Average daily production of liquids (KBBL/d)(1)	884	852	878	908	828
Average daily production of natural gas available for sale (mmCF/d)(1)	4,630	4,734	4,329	4,284	3,782
Average daily production of hydrocarbons available for sale (KBOE/d)(1)	1,732	1,719	1,671	1,688	1,517
Hydrocarbon production sold (mmBOE)	625.0	622.3	608.6	614.1	549.5
Oil and gas production costs per BOE(2)	6.50	6.33	5.90	9.18	12.00
Profit per barrel of oil equivalent(3)	9.27	8.72	1.98	(3.83)	9.86

(1)
Referred to Eni's subsidiaries and its equity-accounted entities. It excludes production volumes of hydrocarbon consumed in operation (119, 97, 88, 73 and 81 KBOE/d in 2018, 2017, 2016, 2015 and 2014 respectively).

(2)
Expressed in U.S. dollars. Consists of production costs of consolidated subsidiaries (costs incurred to operate and maintain wells and field equipment) 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". With effect from January 1, 2018, with a view to conforming to customary industry practice, Eni has changed the method for calculating the average production cost per barrel-of-oil equivalent.

Oil and gas production costs per BOE for prior periods have been recomputed in the table above for comparability. Average production costs no longer include the following items which have previously been included: (i) Royalties and other production taxes; and (ii) Transportation costs relating to the export of the saleable volumes of oil and gas produced, other than the costs incurred to deliver hydrocarbons to a main pipeline, a common carrier, a refinery or a maritime terminal, when unusual physical or operational circumstances exist. If calculated under the previous method, the average production cost for the year 2018 would be $9.33 per boe. Production costs per boe for the comparative periods 2017 and 2016 as previously published and calculated under the previous method were $8.45 and $7.79 respectively. A full reconciliation between recomputed average production costs and originally-published amounts is provided in Item 4 in the "Oil and gas production, production prices and production costs" paragraph of the Exploration & Production section. Prior year data have not been recomputed.

(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.

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Selected Operating Information continued

	Year ended December 31,				
	2018	2017	2016	2015	2014
Worldwide natural gas sales(1)	76.71	80.83	86.31	87.72	86.11
Electricity sold(2)	37.07	35.33	37.05	34.88	33.58
Refinery throughputs(3)	23.23	24.02	24.52	26.41	25.03
Balanced capacity of wholly-owned refineries(4)	388	388	388	388	404
Retail sales (in Italy and rest of Europe)(3)	8.39	8.54	8.59	8.89	9.21
Number of service stations at period end (in Italy and rest of Europe)	5,448	5,544	5,622	5,846	6,220
Chemical production(3)	9.48	8.96	8.81	8.67	7.93
Average throughput per service station (in Italy and rest of Europe)(5)	1,776	1,783	1,742	1,754	1,725
Employees at period end (number)	31,701	32,934	33,536	34,196	34,846

(1)
Expressed in BCM.

(2)
Expressed in TWh.

(3)
Expressed in mmtonnes.

(4)
Expressed in KBBL/d.

(5)
Expressed in thousand liters per day.

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:

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global and regional dynamics of oil and gas supply and demand and global level of inventories. In 2018, the oil market environment was a volatile one. Until October 2018, crude oil prices continued the upward trend commenced in the second half of 2017 driven by economic growth, effectiveness of the production cuts implemented by OPEC Countries and other producers agreed at the end of November 2016 and normalizing inventory level. Geopolitical risks also played a role including production disruption in Venezuela, renewed internal tensions in Libya and worsening relations between USA and Iran. Oil prices peaked in October 2018, touching a four-year high around 85 $/BBL for the Brent crude oil benchmark. Then in November 2018, a sharp downturn, one of the steepest on record, followed driving crude oil prices as low as 60 $/BBL, a correction of about 30%. This downturn was driven by emerging trends pointing to an economic slowdown, uncertainties relating to the developments of the USA-China trade dispute and of the Brexit, and building oversupplies due to rising production levels in USA, OPEC and Russia also in anticipation of the enactment of US sanctions against Iran, which would happen to be less severe than expected. In December 2018, OPEC and Russia agreed to cut again production quotas by 1.2 million bbl/d, effective from January 2019, in an effort to curb a supply glut. In spite of this development, crude oil prices continued to slide throughout December 2018 to the year's lows of 50 $/bbl, extending the correction from the highs to 40%. On average, in 2018 the price for the Brent crude oil benchmark increased by 31% y-o-y at about 71 $/BBL.

In early 2019, oil prices regained the sixty-dollar mark thanks to better-than-expected gauges of economic activity and implementation of the production cuts. In the first quarter of 2019, the Brent crude oil price averaged approximately 63 $/BBL pointing to renewed strength;

- 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;

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- 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;

- rising commitment of the world nations and the civil society 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 hydrocarbons and hence prices of crude oil, natural gas, and other energy commodities.

Management expects global oil demand to grow by approximately 1.4 mmBBL/d in 2019, more or less in line with 2018, and global oil demand and supplies to be balanced overall. Considering the risks of an economic slowdown, geopolitical factors, uncertainties associated with possible developments in the USA-China trade dispute and with the Brexit, management is assuming a Brent price of 62 $/ BBL in 2019, gradually increasing over the following three year period to reach 70$/BBL in 2022. After 2022, management is assuming a price growing in line with inflation (e.g. 71.4 $/BBL in 2023 assuming a long-term inflationary rate of 2%) based on its view of market fundamentals and oil price projections made by specialized agencies and financial analysts, substantially in line with the previous planning assumptions. Management’s oil price forecast was utilized to elaborate the Group financial projections and the level of Group’s capital expenditures for the 2019 – 2022 industrial plan and to estimate recoverability of the carrying amounts of the Group’s oil and gas assets as of December 31, 2018.

Fluctuations in oil and natural gas prices materially affect the Group’s results of operations and business prospects. 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 cash provided by operating activities would vary by approximately €190 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 2019 at 62 $/BBL. Furthermore, a structural decline in commodity prices may have material effects on Eni’s business outlook and may limit the Group’s funds available to finance expansion projects and certain contractual commitments. This because lower oil and gas prices over prolonged periods may adversely affect the funds available to finance expansion projects, further reducing the Company’s ability to grow future production and revenues. In addition, in a weak scenario the Company may also need to review investment decisions and the viability of development projects and capex plans and as a result of this review the Company could reschedule, postpone or curtail development projects.

In case of a structural decline in hydrocarbon prices, the Company may review the carrying amounts of oil and gas properties and this could result in recording material asset impairments. Finally, lower oil and gas prices could result in the de-booking of proved reserves, if they become uneconomic in this type of environment. These risks may adversely impact the Group's results of operations, cash flow, liquidity, business prospects and shareholder returns, including dividends and the share prices.

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 is estimating that approximately 50 per cent of its current production is exposed to fluctuations in hydrocarbons prices. Exposure to this strategic risk is not subject to economic hedging, except for some specific market conditions or transactions. 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

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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 products 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.

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, efficient management of capital resources and the ability to provide valuable services to the energy buyers. 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 in this business may be adversely affected.

- In the Gas & Power segment, Eni is facing strong competition in the European wholesale gas markets to sell gas to industrial customers, the thermoelectric sector and retailer companies from other gas wholesalers, upstream companies, traders and other players both in the Italian market and in markets across Europe. In recent years, competition has been fueled by muted demand growth, oversupplies and the development of very liquid European spot markets where large volumes of gas are traded daily. Players are competing mainly in terms of pricing and to a lesser extent on the ability to offer additional services to the buyers of the commodity, like volume flexibilities, different pricing options, the possibility to change the delivery point and other optionality. Management believes that competition in the European wholesale gas market will continue to negatively affect the results of operations and cash flow of Eni's Gas & Power segment in future reporting periods. Eni's Gas & Power segment also engages in the supply of gas and electricity to customers in the retail markets mainly in Italy, France and other areas in Europe. Customers include households, large residential accounts (hospitals, schools, public administration buildings, offices) and small and medium-sized businesses located in urban areas. The retail market is characterized by strong competition among local selling companies which mainly compete in term of pricing and the ability to bundle valuable services with the supply of the energy commodity. In this segment competition has intensified in recent years due to the

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progressive liberalization of the market and the option on part of residential customers to switch smoothly from one supplier to another. Management believes that competition will represent a risk factor to the Company's results of operations and cash flow in this business unit.

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Eni is facing strong competitive pressure in its business of gas-fired electricity generation which is largely sold at wholesale markets in Italy. Margins on the sale of electricity have declined in recent years due to oversupplies, weak economic growth and inter-fuel competition. This latter was due to the fact that power produced from renewable sources and coal-fired power generation are cheaper than gas-fired electricity, although coal-fired plants are expected to be progressively phased-out due to environmental issues. Management believes that these negative factors will continue to negatively affect crack-spread margins on electricity at Italian wholesale markets and the profitability of this business unit in the foreseeable future.

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In the Refining & Marketing segment, Eni faces strong competition both in the wholesale markets and in the retail marketing activity. Margins of European refiners are facing structural headwinds due to muted trends in the European demand for fuels and continued competitive pressures from players in the Middle East, the USA and Asia, who can leverage on larger plant scale and cost economies, availability of cheaper feedstock, lower energy expenses and fewer environmental obligations. Eni believes that the competitive environment will remain challenging in the foreseeable future, also considering refining overcapacity in the European area and expectations of a new investment cycle driven by capacity expansion plans announced in Asia and the Middle East, potentially leading to a situation of global oversupplies of refinery products. In 2018 Eni's gauge of profitability in the refining business fell by approximately 26% to 3.7 $/BBL driven by rising costs of oil-based feedstock that the Company was unable to transfer to final products prices pressured by the weak market fundamentals described above. This decline negatively affected the performance of the Company's refining activity. Management believes that in the long-term the trading environment will not recover meaningfully with refining margins seen in a 4-5 $/BBL range. Furthermore, Eni's refining margins are exposed to the volatility in the spreads between crudes with high sulfur content or sour crudes vs. the Brent crude benchmark, which is a low-content sulfur crude. Eni complex refineries are able to process sour crudes which typically trade at a discount over the Brent crude. However, in 2019 a shortfall in supplies of sour crudes is expected in the market due to the production cuts implemented by OPEC, lower exports from Venezuela and the USA sanctions against Iran. Those developments could result in an appreciation of the relative prices of sour crudes vs. the Brent, which would negatively affect the results of our refining business. Against this backdrop, management has designed an action plan intended to reduce the Company's breakeven margin in its refining business to about 3 $/BBL in 2019 by means of plant and feedstock optimization, energy savings and other cost efficiencies. Additionally, management expects to close by year-end the acquisition of a 20%-stake in a large refining asset in Abu Dhabi, which will de-risk Eni's refining business due to the fact that the asset being acquired is more profitable than Eni's legacy refineries due to larger scale, efficiency, geographic reach and proximity to raw materials sources. In case management fails to execute on this plan, the profitability of Eni's refining business may be negatively affected considering management's expectations for a weak trading environment. In marketing, Eni faces competition from other oil companies and newcomers such as low-scale operators and large retailers, who tend to adopt aggressive pricing policies. All these operators compete with each other primarily in terms of pricing and, to a lesser extent, service quality.

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In the Chemicals business, Eni faces strong competition from well-established international players and state-owned petrochemical companies, particularly in the most commoditized market segments such as the production of basic petrochemical products (like ethylene and polyethylene), which demand is a function of macroeconomic growth. Many of those competitors based in the Far East and the Middle East are able to benefit from cost economies due to larger plant scale, wide geographic moat, availability of cheap feedstock and proximity to end-markets. Excess capacity across Europe has also fueled 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 from which ethane is derived which is a cheaper raw material for the production of ethylene than the oil-based feedstock utilized by Eni's petrochemicals subsidiaries. In 2018 the operating profit of our Chemicals business fell sharply due to increased expenses for oil-based feedstock, which the Company was not able to pass to final products prices pressured by competition. The Company does not expect any meaningful improvement in the trading environment in the short to the medium-term due to competitive headwinds described above.

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Management intends to execute an action plan designated to diversify the product portfolio away from the more commoditized products which are exposed to crude oil prices fluctuations and cyclical market dynamics and to focus on higher-value added products, particularly in the green chemicals business and in specialty niche markets, which we believe are less exposed to the economic cycle and to the volatility of crude oil prices. If the Company fails to reduce its exposure to commodity plastics and to gain critical mass in the green chemicals business and in the specialty markets, its future results of operations and cash flows may remain cyclical and exposed to any demand or cost downturn.

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. Technical faults, malfunction of plants, equipment and facilities, control systems failure, human errors, acts of sabotage, loss of containment and adverse weather events can trigger damaging events such as explosions, fires, oil and gas spills from wells, pipeline and tankers, release of contaminants, toxic emissions and other negative events.

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 petrochemical 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.

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 has invested and will continue to invest 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 be completely successful in protecting against

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those 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 and to negatively affect results and cash flow and the Company's business prospects.

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 unfavorable events and in connection with environmental clean-up and remediation. Maximum compensation is $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 exploration and production activities are subject to the mining risk and the risks of cost overruns and delayed start-up at the projects to develop and produce hydrocarbons reserves. Those risks could have an adverse, significant impact on Eni's future growth prospects, results of operations, cash flows, liquidity and shareholders' returns.

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 2018, approximately 56% 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, Indonesia, Venezuela, the

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United Arab Emirates, 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 future growth prospects, results of operations, cash flows, liquidity, reputation and shareholders' returns.

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 and completing 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. A large part of the Company exploratory drilling operations is located offshore, including in deep and ultra-deep waters, in remote areas and in environmentally sensitive locations (such as the Barents Sea, the Gulf of Mexico and the Caspian Sea). In these locations, the Company generally experiences higher operational risks and more challenging conditions and incurs higher exploration costs than onshore. Furthermore, deep and ultra-deep water operations require significant time before commercial production of discovered reserves can commence, increasing both the financial risks associated with these activities. Because Eni plans to make significant 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, cash flows 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 in environmentally-sensitive locations. Eni's future results of operations and business prospects 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 to define project terms and conditions, including, for example, Eni's ability to negotiate favorable long-term contracts to market gas reserves;

- commercial arrangements for pipelines and related equipment to transport and market hydrocarbons;

- timely issuance of permits and licenses by government agencies;

- the ability to make the 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;

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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;

- performance in project execution on the part of contractors who are awarded project construction activities generally based on the EPC (Engineering, Procurement and Construction) contractual scheme;

- changes in operating conditions and cost overruns;

- 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 the technical and economic feasibility of the development project, project final investment decision and building and commissioning the related plants and 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 capitalised 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”), whereby the Company 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, and vice versa. Based on the current portfolio of oil and gas assets, Eni’s management estimates that production entitlements vary on average by approximately 600 BBL/d for each $1 change in oil prices based on current Eni’s assumptions for oil prices. This led to negative reserves revisions of 38 mmBOE in 2018, due to the oil price increase previously described. In case oil prices differ significantly from Eni’s own forecasts, the result of the above mentioned sensitivity of production to oil price changes may be significantly different.

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.

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;

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- 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.
The prices used in calculating Eni's estimated proved reserves are, in accordance with the U.S. Securities and Exchange Commission (the "U.S. SEC") requirements, calculated by determining the unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding 12 months. For the 12-months ending December 31, 2018, average prices were based on 71.4 $/BBL for the Brent crude oil.
Brent prices have declined significantly since they reached a peak at 85 $/BBL in October of 2018 and in the first quarter of 2019 have recovered only partially. If such prices do not increase significantly in the coming months, our future calculations of estimated proved reserves will be based on lower commodity prices which could result in our having to remove non-economic reserves from our proved reserves in future periods. This effect could be counterbalanced in full or in part by increased reserves corresponding to the additional volume entitlements under Eni's PSAs relating to cost oil: i.e. because of lower oil and gas prices, the reimbursement of expenditures incurred by the Company requires additional volumes of reserves.
Accordingly, the estimated reserves reported as of the end of 2018 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 business prospects, results of operations, cash flows and liquidity.
The development of the Group's proved undeveloped reserves may take longer and may require higher levels of capital expenditures than it currently anticipates or the Group's proved undeveloped reserves may not ultimately be developed or produced.
At December 31, 2018, approximately 32% 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 December 31, 2018 includes estimates of total future development and decomissioning costs associated with the Group's proved total reserves of approximately €35.3 billion (undiscounted, including consolidated subsidiaries and equity-accounted entities). 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 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%.

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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.

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% 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. At December 31, 2018, the net present value of Eni's proved reserves totaled approximately €57.6 billion. The average prices used to estimate Eni's proved reserves and the net present value at December 31, 2018, as calculated in accordance with U.S. SEC rules, were 71.4 $/BBL for the Brent crude oil. Actual future prices may materially differ from those used in our year-end estimates. Commodity prices have decreased significantly in recent months. Holding all other factors constant, if commodity prices used in Eni's year-end reserve estimates were in line with the pricing environment existing in the first quarter of 2019, Eni's PV-10 at December 31, 2019 could decrease significantly.

Oil and gas activity may be subject to increasingly high levels of regulations throughout the world, which may impact our extraction activities and the recoverability of reserves

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, environmental protection measures, control over the development and abandonment of fields and installations, and restrictions on production. These risks can limit the Group access to hydrocarbons reserves or may have the Group to redesign, curtail or cease its oil&gas operation with significant effects on the Group business prospects, results of operations and cash flow.

In Italy, a new law has been enacted effective February 12, 2019, which requires certain Italian administrative bodies to adopt within eighteen months a plan intended to identify areas that are suitable for carrying out exploration, development and production of hydrocarbons in the national territory, including

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the territorial seawaters. Until approval of such a plan, it is established a moratorium on exploration activities, including the award of new exploration leases. Following the plan approval, exploration permits resume their efficacy in areas that have been identified as suitable; on the contrary, in unsuitable areas, exploration permits are repealed.

As far as development and production concessions are concerned, pending the national plan approval, ongoing concessions retain their efficacy and administrative procedures underway to grant extension to expired concession remain unaffected; instead no applications to obtain new concession can be filed. Once the above mentioned national plan is adopted, development and production concessions that fall in suitable areas can be granted further extensions and applications for new concessions can be filed; on the contrary development and production concessions current at the approval of the national plan that fall in unsuitable areas are repealed at their expiration and no further extensions can be granted, nor new concession applications can be filed.

In case Italian administrative bodies fail to adopt the national plan for suitable areas within two years from the law enactment, the general moratorium on exploration activities is revoked and application for new concession permits can be filed. According to the statute, areas that are suitable to the activities of exploring and developing hydrocarbons must conform to a number of criteria including morphological characteristics and social, urbanistic and industrial constraints, with particular bias for the hydrogeological balance, current territorial planning and with regard to marine areas for externalities on the ecosystem, reviews of marine routes, fishing and any possible impacts on the coastline.

Our largest development project in Italy is operated under a concession that will expire in 2019; the application for renewal is underway and the renewal process is unaffected by the new law; assuming it is renewed as expected, this concession will expire in 2029, unless renewed at that time. Production at those sites is currently scheduled to continue until 2045.

Management believes the criteria laid out in the law for identified unsuitable areas to be high-level principles, which make it difficult identifying in a reliable and objective manner areas that might be suitable or unsuitable to hydrocarbons activities before the plan adoption by Italian authorities. Therefore, management is not currently in the position to make a reliable and fair estimation of future impacts of the new law provisions on the recoverability of the volumes of proved reserves booked in Italy and the associated future cash flows. However, based on the review of all facts and circumstances and on the current knowledge of the matter, management does not expects any material impacts on the Group future results of operations and cash flow.

Political considerations

The large majority of Eni’s oil and gas reserves are located in countries outside Europe and North America, mainly in Africa, Central Asia and Central-Southern America, where the socio-political framework, the financial system and the macroeconomic outlook are less stable than in the OECD countries. In those non-OECD countries, Eni is exposed to a wide range of additional risks and uncertainties in addition to the material risks described above, which could materially impact the ability of the Company to conduct its oil&gas operations in a safe, reliable and profitable manner.

As of December 31, 2018, approximately 82% of Eni’s proved hydrocarbon reserves were located in such 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 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;

- unfavorable 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

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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;

- sovereign default or financial instability due to the fact that those Countries rely heavily on petroleum revenues to sustain public finance and petroleum revenues have dramatically contracted during the recent, three-year long oil downturn which ended by mid of 2017. 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 events. 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 authorizations 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 and Iraq. 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 a change of regime, which caused a prolonged period of political and social instability, still ongoing. In 2011 Eni's operations in the country experienced an almost one-year long shutdown due to security issues amidst a civil war, causing a material impact on the Group results of operation and cash flow of the year. In subsequent years Eni has experienced frequent disruptions at its operations albeit of a smaller scale than in 2011 due to security threats to its installations and personnel. In the second half of 2018 a resurgence of socio-political instability coupled with internal clashes reduced the Country economic activity and gas demand which negatively affected the Company's levels of production for the year. Management is closely monitoring the situation and is evaluating any possible measure to safeguard safety of Eni's local personnel and security of plants and production infrastructures. Going forward, management believes that Libya's geopolitical situation will continue to represent a source of risk and uncertainty to Eni's operations in the Country. Currently, Libya represents approximately 16% of the Group's total production; this proportion 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 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, which have negatively affected the Country production levels and hence petroleum revenues. The situation has been made worse by certain international sanctions targeting the country's financial system and its ability to export crude oil to the USA market, which is the main outlet of Venezuelan production, which are described below. Eni expects the financial and political outlook of Venezuela to negatively affect its ability to recover the investments made in the Country to develop two petroleum projects and the overdue trade receivables owned to us by the Venezuelan national oil company – PDVSA – and its affiliates for the gas supplies of the Cardon IV gas project, a 50 per cent. – held joint venture. In 2018, this venture was able to collect a

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certain percentage of the sales of the equity gas produced in the year to PDVSA. The venture is systematically accounting a loss provision on the uncollected revenues based on management's appreciation of the counterparty risk which was estimated based on the findings of a review of the past experience of sovereign defaults. Furthermore, due to a worsening operating environment, management decided to de-book the proved undeveloped reserves (down 106 million BBL) at one of the Company's projects in the Country, recognizing an impairment loss of around €200 million.

Nigeria is also undergoing a situation of financial stress, which has translated into continuing delays in collecting overdue trade receivables and credits for the carry of the expenditures of the Nigerian joint operators at projects operated by Eni 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.

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

In Egypt, Eni plans to invest significantly in the next four-year plan to sustain the production plateau at the Zohr offshore gas field and to develop existing gas reserves at other projects. Since our gas production is entirely sold to local state-owned oil companies, we expect a significant increase in the credit risk exposure in Egypt, where we experienced some issues at collecting overdue trade receivables during the downturn. Eni will continue monitoring the counterparty risk in future years considering the significant volumes of gas expected to be supplied to Egypt's national oil companies.

Eni closely monitors political, social and economic risks of the 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.

Sanction targets

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 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, while currently the Company is not engaged in any upstream projects 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 prohibit any US person to be involved in all transactions related to, provision of financing for, and other dealings in, among other things, any debt owed to the Government of Venezuela that is pledged as collateral after the effective date, including accounts receivable. Recently the US administration has resolved to impose an embargo on the import of crude oil from Venezuela state-owned oil company, PDVSA and has restricted the ability of US dealers to trade bonds issued by the Government of Venezuela and its affiliates. These sanctions do not affect directly Eni's activities, which however are affected by the worsening financial, political and operating outlook of the country which could limit the ability of Eni to recover its investments.

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Risks in the Company's Gas & Power business

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

Until 2018, our Gas & Power segment has recorded a history of weak profitability and losses due to the changed fundamentals of the wholesale gas markets in Europe following the gas downturn of 2013 – 2014. Competition escalated driven by muted demand growth, oversupplies and the increasing weigh in the European energy mix of governmental-subsided renewable energy sources (particularly the photovoltaic). The large-scale development of shale gas in the United States was another factor contributing to the oversupply situation in Europe, because many LNG projects worldwide that originally targeted the US market were redirected to an already saturated European market. Furthermore, a number of re-gasification terminals in the US have been upgraded to gas liquefaction facilities with the aim of exporting the US gas surplus. Large gas supplies to Europe led to the development of liquid spot markets where gas is traded daily. Prices at those hubs became the main indexation parameter of selling prices, replacing prices contractually agreed in bilateral negotiations between gas buyers and gas wholesalers. Increased competition, market liquidity and indexation mismatch between gas purchase prices and selling prices determined a squeeze of margins on gas sales. These trends were exacerbated by the contractual commitments taken by the Company to supply gas to end-markets in Europe. A few years ago, before the onset of the European gas downturn, the Company signed with the main countries supplying gas to Europe (Russia, Algeria, the Netherlands, Libya and Norway) long-term gas supply contracts with take-or-pay clauses, which would expose us to a volume risk, as the Company was contractually required to purchase minimum annual amounts of gas or, in case of failure, to pay the corresponding price. Additionally, Eni booked the transportation rights along the main gas backbones across Europe to deliver its contracted gas volumes to end-markets. In a weak market, the need to dispose of the minimum off-take of gas negatively affected Eni's margins. Those market trends have negatively affected the operating performance of our Gas & Power segment from the beginning of the market crisis throughout 2017, when this segment closed at breakeven. However, in 2018 the segment posted a significant recovery in profitability due to the benefits of the renegotiations of its long-term gas supply contracts and other drivers. Furthermore, in 2018 gas demand and supplies in Europe were more balanced due to a certain recovery in demand supported by the phase out of a number of coal-fired power plants and lower production from nuclear plants, a slowdown in the final investment decisions in new liquefaction capacity due to the oil downturn and increasing gas demand from China. Looking forward, the Company expects that a muted demand environment in Europe driven by an ongoing economic slowdown will increase the risks of oversupplies and margin pressure.

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 due to the costs of logistics and other factors. This price differential enables the Company to recover its fixed operating expenses in the gas wholesale business. Risks are raising that spot prices in Italy could converge with prices at continental hubs due to the current slowdown of gas demand in Europe and in Italy and the return of LNG spot volumes at European markets and also at Italian regasification terminals. Longer-term there are risks of an oversupply build in the Italian market due to the expected entry into operations of a project to import gas from the Caspian region to Italy and other developments. A reduction of the spread between Italian spot prices and European spot prices for gas could negatively affect the profitability of our business by reducing the total addressable market and the related opportunities to monetize the flexibilities of our gas portfolio, as in the case of the possibility to lift additional gas volumes in addition to the annual minimum quantity at our take-or-pay contracts up the annual contractual quantity in case of favorable market conditions.

Eni's management is planning to continue its strategy of renegotiating the Company's long-term gas supply contracts in order to constantly align pricing and volume terms to current market conditions as they evolve, considering the risk factors described above. The revision clauses provided by these contracts state

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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 and may also claim an increase in the price of the gas supplied to Eni based on their own view of markets dynamics. 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 the years preceding the European gas downturn of 2013 – 2014, Eni signed a number of long-term gas supply contracts with national operators of certain key producing countries, from where most of the European gas supplies are sourced (Russia, Algeria, Libya, the Netherlands and Norway). These contracts were intended to secure Eni long-term access to gas supplies, particularly with a view to supplying the Italian gas market and in anticipation of certain pargets of gas demand growth, which however would fall short of industry's projections.

These contracts include take-or-pay clauses whereby the Company has an obligation to lift 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 obligated to purchase an annual minimum volume of gas, or in case of failure, to pay the underlying price.

Management believes that the current level of market liquidity, the outlook of the European gas sector which is featuring muted demand growth, strong competitive pressures and large supplies, as well as any possible change in sector-specific regulation represent risk factors to the Company's ongoing 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. 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 until the market is fully opened.

Developments in the regulatory framework intended to increase the level of market liquidity or of de-regulation, or intended to reduce operators' ability to transfer to customers cost increases in raw materials may negatively affect future sales margins of gas and electricity, operating results and cash flow.

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

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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 set limits to the emission of scrap substances and pollutants and discipline the handling of hazardous materials and discharges of water contaminants nad nocive air emissions 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 or operated 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.

Breaches of environmental, health and safety laws and regulations as in the case of negligent or willful release of pollutants into the atmosphere, the soil or groundwater or the overcome of concentration threshold of contaminants set by the law expose the Company to the incurrence of liabilities associated with compensation for environmental, health or safety damage and expenses for environmental remediation and clean-up. Furthermore, in the case of violation of certain rules regarding the safeguard of the environment and safety in the workplace and of communities, the Company may be liable for the negligent or willful conduct on part of its employees as per Italian Law Decree No. 231/2001, which assumes that any misconduct of employees in the field of environmental and health matters can be ascribed to the Company.

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, water, ground or air contaminants or pollutants, 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.

As a further result of any new laws and regulations or other factors, like the actual or alleged occurrence of environmental damage at Eni's plants and facilities, the Company may be forced 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, cash flow and liquidity.

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.

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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, environmental damage, 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, discharge of toxic materials, 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, cash flow, financial condition, business prospects, reputation and shareholders' value, including dividends and the share price.

Rising public concern related to climate change has led and could continue to lead to the adoption of national and international laws and regulations which are expected to 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 unpredictable 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 business and reputation, increase its operating costs and reduce its results of operations, cash flow, financial condition, business prospects and shareholders returns. Those risks may emerge in the short and medium-term, as well as over the long-term.

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The scientific community has established a link between climate change and increasing GHG concentration in the atmosphere. International efforts to limit global warming have led, and Eni expects them to continue to lead, to new laws and regulations designed to reduce GHG emissions that are expected to bring about a gradual reduction in the use of fossil fuel over the medium to long-term, notably through the diversification of the energy mix.

Governmental institutions have responded to the issue of climate change on two fronts: on one side, governments can both impose taxes on GHG emissions and incentivize a progressive shift in the energy mix away from fossil fuels, for example, by subsidizing the power generation from renewable sources.

Some governments have already introduced carbon pricing schemes, which can be an effective measure to reduce GHG emissions at the lowest overall cost to society. Today, about half of the GHG direct emissions coming from Eni operated assets are already included in national or supranational Carbon Pricing Mechanisms, such as the European Emission Trading Scheme. Eni expects that more governments will adopt similar schemes and that a growing share of the Group's GHG emissions will be subject to carbon-pricing and other forms of climate regulation in the short to medium term. Eni expects that governments require companies to apply technical measures to reduce their GHG emissions. Eni is already incurring operating costs related to its participation in the European Emission Trading Scheme, whereby Eni is required to purchase on the open markets emission allowances in case its GHG emissions exceed freely-assigned emission allowances (see Note 27 to the Financial Statements). In 2018 to comply with this carbon emissions scheme, Eni purchased on the open market allowances corresponding to 12.7 million tonnes of CO_2 emissions. In certain jurisdictions, Eni is also subject to carbon pricing schemes in Norway. Due to the likelihood of new regulations in this area, Eni expects 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 operating costs and results of operations, cash flow, financial condition, business prospects and shareholders' returns. Eni also expects that governments will also require companies to apply technical measures to reduce their GHG emissions.

Eni expects that the achievement of the Paris Agreement goal of holding the increase in global average temperature to less than 2° C above pre-industrial levels, or the more stringent goal advocated by the Intergovernmental Panel on Climate Change (IPCC) to limit global warming to 1.5°C, will strengthen the global response to the threat of climate change and spur governments to introduce further measures and policies targeting the reduction of GHG emissions, which will reduce local demand for fossil fuels, thus negatively affecting global demand for oil and natural gas. Eni's business depends on the global demand for oil and natural gas. If 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 by a large amount, Eni's results of operations, cash flow, financial condition, business prospects and shareholders' returns may be significantly and adversely affected.

The scientific community has concluded that increasing global average temperatures produces 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. Extreme and unpredictable weather phenomena can result in material disruption to Eni's operations, and consequent loss of or damage to properties and facilities, as well as a loss of output, loss of revenues, increasing maintenance and repair expenses and cash flow shortfall.

Finally, there is a reputational risk linked to the fact that oil companies are increasingly perceived by institutions and the general public as the entities responsible of the global warming due to GHG emissions across the value chain and in particular related with the use of energy products. This could possibly make Eni's shares less attractive to investment funds and individual investors who have been more and more assessing the risk profile of companies against their carbon footprint when making investment decisions. This trend could have a material adverse effect on the price of our securities and our ability to access equity or other capital markets. Additionally, the World Bank has announced plans to stop financing upstream oil and gas projects in 2019. Similarly, according to press reports, other financial institutions also appear to be considering limiting their exposure to certain fossil fuel projects. Accordingly, our ability to use financing for future projects may be adversely impacted. This could also adversely impact our potential partners' ability to finance their portion of costs, either through equity or debt.

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Further, in some countries, governments and regulators have filed lawsuits seeking to hold fossil fuel companies, including Eni, liable for costs associated with climate change. Losing any of these lawsuits could have a material adverse effect on our results of operations, cash flows, liquidity and business prospects.

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

Eni is the defendant in a number of civil and criminal actions and administrative proceedings. In addition to existing provisions accrued as of December 31, 2018 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 in which Eni or its subsidiaries or its officers and employees are defendant involve the alleged breach of anti-bribery and anti-corruption laws and regulations and other ethical misconduct. Such proceedings are described in Note 27 to the 2018 Consolidated financial statements, under the 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, expected synergies from acquisition may fall short of management’s targets and Eni’s financial performance and shareholders’ returns may be adversely affected.

Risks deriving from Eni’s exposure to weather conditions

Significant changes in weather conditions in Italy and in the rest of Europe from year to year may affect demand for natural gas and some refined products. In colder years, demand for such products is higher. Accordingly, the results of operations of the Gas & Power segment and, to a lesser extent, the Refining & Marketing 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, which includes exposure to market risk, including commodity price risk, interest rate risk and foreign currency risk, as well as liquidity risk, and credit risk.

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

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 shareholders' equity. The Exploration & Production segment is particularly affected by movements in the 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 and cash flows.

Susceptibility to variations in sovereign rating risk

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

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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 business prospects, results of operations and cash flows, 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 and production of oil and natural gas reserves. Over the next four years, the Company plans to invest in the business approximately €33 billion, approximately 50% of capital expenditures at the end of the four-year period refers to uncommitted projects, granting to the Group financial flexibility in case of sudden changes in the trading environment. In 2019, Eni expects to make capital expenditures of approximately €8 billion, in line with 2018. 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.

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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 and to the fact that Italy, which is still the largest market to Eni's gas wholesale and retail businesses, has underperformed other OECD countries in terms of GDP growth. Management believes that the Gas&Power segment 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. Going forward, we expect that an uncertain macroeconomic outlook in Europe and Italy will pose a risk to the Company's ability to collect revenues in its retail gas and power business.

Eni's E&P business is significantly exposed to the credit risk because of the deteriorated financial outlook of many oil-producing countries due to a three-year long downturn in oil prices, which has negatively impacted petroleum revenues and cash reserves. Certain countries where Eni is engaging in oil&gas operations have yet to recover from the oil downturn. 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.

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.

Disruption to or breaches of Eni's critical IT services or information security systems could adversely affect the Group's activities.

The Group's activities depend heavily on the reliability and security of its information technology (IT) systems. The Group's IT systems, some of which are managed by third parties, are susceptible to being compromised, damaged, disrupted or shutdown due to failures during the process of upgrading or replacing software, databases or components, power or network outages, hardware failures, cyber-attacks (viruses, computer intrusions), user errors or natural disasters. The cyber threat is constantly evolving. Attacks are becoming more sophisticated with regularly renewed techniques while 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. The Group and its service providers may not be able to prevent third parties from breaking into the Group's IT systems, disrupting business operations or communications infrastructure through denial-of-service attacks, or gaining access to confidential or sensitive information held in the system. The Group, like many companies, has been and expects to continue to be the target of attempted cybersecurity attacks. While the Group has not experienced any such attack that has had a material impact on its business, the Group cannot guarantee that its security measures will be sufficient to prevent a material disruption, breach or compromise in the future.

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 could occur, potentially having a material adverse effect on the Group's financial condition, including its operating income and cash flow.

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The United Kingdom leaving the European Union may affect the Group's results

On 23 June 2016, the UK held a referendum to decide on the UK's membership of the European Union. The UK vote was to leave the European Union. There are a number of uncertainties in connection with the future of the UK and its relationship with the European Union. The negotiation of the UK's exit terms is likely to take a number of years. Until the terms and timing of the UK's exit from the European Union are clearer, it is not possible to determine the impact that the referendum, the UK's departure from the European Union and/or any related matters may have on the business of the Issuer.

As such, no assurance can be given that such matters would not adversely affect the Company's business prospects, results of operations, cash flows and liquidity.

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Item 4. INFORMATION ON THE COMPANY

History and development of the Company

Eni SpA with its consolidated subsidiaries engages in the 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 67 countries and 31,701 employees as of December 31, 2018.

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 43 countries, including Italy, Libya, Egypt, Norway, the United Kingdom, Angola, Congo, Nigeria, the United States, Kazakhstan, Algeria, Australia, Iraq, Indonesia, Ghana, Mozambique, Oman and United Arab Emirates. In 2018, Eni average daily production amounted to 1,732 KBOE/d on an available-for-sale basis. As of December 31, 2018, Eni's total proved reserves amounted to 7,153 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 that is ancillary to the marketing of electricity. In 2018, Eni's worldwide sales of natural gas amounted to 76.71 BCM, of which 39.03 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, 2018. In 2018, electricity sold totalled 37.07 TWh. The LNG business includes the purchase and marketing of LNG worldwide, with a large incidence of equity LNG supplies. The Group serves the gas and power wholesale and retail markets in Italy and in a number of European markets. As at December 31, 2018 the Gas & Power segment had 9.2 million retail customers. The Gas & Power segment comprises results of the Group activities intended to manage commodity risk of asset-backed trading activities and proprietary trading. Furthermore, this activity includes the result of crude oil and products supply, trading and shipping.

Eni's Refining & Marketing and Chemical segment includes the result of the R&M business and of the chemicals business.

The R&M business engages in crude oil supply and refining and 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 2018, processed volumes of crude oil and other feedstock, including renewable feedstock, amounted to 23.48 mmtonnes (of which traditional refinery throughputs were 23.23 mmtonnes and green refinery throughputs were 0.25 mmtonnes) and sales of refined products were 32.92 mmtonnes, of which 25.91 mmtonnes in Italy. Retail sales of refined products at Eni's service stations amounted to 8.39 mmtonnes in Italy and in the rest of Europe. In 2018, Eni's retail market shares in Italy through its "Eni" branded network of service stations was 24%.

In the Chemical business Eni, through its wholly-owned subsidiary Versalis, engages in the production and marketing of basic petrochemical products, plastics and elastomers. Versalis is developing the business of green chemicals. Activities are concentrated in Italy and in Europe. In 2018, production volumes of petrochemicals amounted to 9,483 ktonnes. The results of Versalis have been aggregated with those of R&M, in the reportable segment "R&M and Chemicals" because the two businesses exhibit similar economic characteristics.

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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 37 – 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 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 expenditure and dividend payments – and to preserve a solid balance sheet. In 2018 we made substantial progress in delivering on our financial targets leveraging on a recovery in crude oil prices, which lasted ten months until October 2018, and on an improved underlying performance. We reported a better cash flow from operating activities and an improvement in the Group financial condition. These achievements were driven by our successful exploration activity which contributed to reserve replacement and cash generation by means of our dual exploration model, cost and capital discipline, reducing the time to market of reserves, growing profitably hydrocarbons production, restructuring our loss-making mid and downstream business that are currently generating structural positive results, pursuing integration across businesses and finally process simplification and streamlining. In 2018 we made substantial progress in enlarging the geographic reach of our asset portfolio and in rebalancing the business along the hydrocarbons "value chain" by making strategic acquisitions in the Middle East which comprised exploration and development properties in the UAE and elsewhere in the region and a deal under completion to acquire a 20% interest in the Ruwais refining complex in the UAE. This deal is expected to be finalized by year end. See the paragraph below for more details about our expansion in the Middle East.

Looking forward we plan to enhance value generation across all our businesses by developing the growth opportunities associated with the purchased assets in the Middle East and by maturing the other grow initiatives under execution. The strategic guidelines going forward are:

- Growing oil&gas production with improving returns leveraging on the organic developments of our discoveries and full ramp up at our core producing fields and fields started in 2018;
- Retaining a strong focus on exploration activities to ensure reserve replacement, diversification of geographies and opportunities to deploy our dual exploration model;
- Strengthening results and cash generation in our mid and downstream businesses through contract renegotiations, selective growth initiatives, improvement of plant reliability, higher flexibility in raw materials and feedstock, innovation in products and services, and cost efficiencies;
- Pursuing margin and growth opportunities through enhanced business integration;
- Financial discipline;
-

Increased digitalization to support operations efficiency;

•

Reducing the carbon footprint of the Company by means of increasing efficiency and developing the green businesses and the industrial initiatives intended to promote a circular economy.

Implementation of this strategy will be supported by a capital plan of €33 billion, approximately 77% of which will be destined to finding and developing hydrocarbons reserves.

We believe that the action plan we have designed for the next four-year period 2019 – 2022 at the Company's Brent scenario of $62 in 2019 subsequently increasing to our long-term case of $70 will improve the Company's profitability and cash generation reducing further our cash neutrality. We remain committed to our progressive distribution policy in line with the expected growth in underlying earnings and cash flow. See Item 5 – Management Expectations of Operation.

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Strategy for a low-carbon environment

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

- The first is to retain a portfolio of oil&gas projects that we believe are resilient to a low carbon scenario

- The second is our action plan to lower CO2 emissions in all our operations, particularly to reduce the energy intensity at our exploration and production activities and improve energy efficiency across all business lines;

- Thirdly, we intend to grow our business of power generation produced by renewable sources, to develop the forestry business, to increase production of bio-fuels and to execute several industrial projects designed to recycle organic waste and other civil waste aiming at producing energy or raw materials to produce bio-fuels or bio-chemicals as well as to revitalize dismissed or decommissioned industrial sites;

- Finally, R&D will play a key role in our decarbonization strategy.

Our portfolio of oil and gas properties features a large weight of natural gas, the least GHG-emitting fossil energy source, which represented approximately 49% of Eni's production in 2018 on an available-for-sale basis; as of 31 December 2018, gas reserves represented approximately 50% of Eni's total proved reserves of its subsidiary undertakings and joint ventures. The other pillar of our resilient portfolio of oil&gas properties is the high incidence of conventional projects, developed through phases and with low CO2 intensity. We estimate that the new oil&gas projects under execution, which will attract some 45% of the projected development expenditures in the next four-year plan, have a price breakeven of around 25 $ per barrel. We believe that those elements of our portfolio will mitigate the risk of stranded reserves going forward due to risks of lower hydrocarbons demand in response to stricter global environmental constraints and regulations and increasing public sensitivity to the issue of global warming. Eni's portfolio exposure to those risks 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) Eni's management estimation of a cost per ton of carbon dioxide (CO2) equivalent of 40 $/tonnes in real terms 2015, which is applied to the total GHG emissions of each capital project, while retaining the management scenario for hydrocarbons prices; and 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 on a regular basis, to monitor the progress of each project. The review performed at the end of 2018 indicated that the internal rates of return of Eni's ongoing projects in aggregate should not be substantially 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. The majority of the projects have GHG intensity targets that allow them under current assumptions to compete 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 the economic conditions imposed by new 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 set forth in 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 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 of reducing 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 hydrocarbons pricing assumptions of the IEA SDS scenario are more optimistic than Eni's scenario, particularly the IEA SDS scenario projects crude oil prices to be much higher than Eni's crude oil pricing assumptions. On the other hand, CO2 emissions costs under the IEA SDS assumptions will show a strong uptrend consistent with the goal of encouraging the adoption of low carbon technologies. Such CO2 emissions costs as estimated by the IEA SDS would reach up to 140 $ per ton in real terms in 2040, which is higher than Eni's CO2 pricing trends and assumptions for the medium-long term. Nevertheless, the sensitivity test performed at Eni's oil&gas CGUs under the IEA SDS assumptions indicated the resiliency of Eni's asset portfolio in terms of carrying amounts and fair value, because the loss of value that would result from the higher CO2 costs assumed by the IEA SDS (in comparison to Eni's projections) is outweighed by higher assumptions for crude oil prices assumed in the IEA SDS scenario.

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In October 2018 the Intergovernmental Panel on Climate Change (IPCC) stated, in a new report, that in order to limit global warming to 1.5°C, the world economy would need to undertake a deeper and complex transformation. We recognize that meeting this challenge in the next decades requires an even more rapid escalation, both in term of size and speed, of changes than were foreseen in the Paris Agreement. Currently, this scenario has yet to be complemented by a full set of pricing and other operating assumptions, which once available from the IPCC or other sources will be deeply analyzed by the Company for the purpose of updating stress-testing models and methodologies.

To strengthen the resiliency of our oil&gas portfolio, we are fully committed to reduce the energy intensity at our oil and gas projects. In 2018 we reduced the energy intensity in our E&P business to 21.44 tonnes of CO_2 equivalent per thousand of BOE, down by 6% y-o-y and by 20% from 2014 levels. This measure relates to gross operated production. By 2030 we are targeting to achieve net zero emissions in our upstream business (on equity basis) by:

– Increasing efficiency to minimize direct upstream CO_2 emissions. As part of this target by 2025 we plan to eliminate gas process flaring and reduce methane emissions by 80%; and

– offsetting residual upstream emissions through large forestry projects.

Going forward, our de-carbonization strategy will be underpinned by the development of the business of power generation from renewable sources, growth at our green business lines and implementation of a number of industrial projects designed to promote the circular economy. These projects will attract some €3 billion, or 9% of the Group planned capex for the four-year period 2019 – 2022, including projects designed to reduce gas flaring and improve energy efficiency across all business lines.

The renewable power generation business will comprise an expansion plan of generation capacity fueled by photovoltaic or wind power, targeting a total installed capacity of 1.6 GW by 2022 through the execution of more than sixty projects. The green business involves the production of bio-fuels and bio-chemicals at our green refineries and chemical hubs. This business will be enhanced due to the completion of the second upgrading phase at our Venice bio-refinery and the start-up of the Gela bio-refinery which are designed to process vegetable feedstock to produce high-quality automotive fuels. 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. The green business at our chemical subsidiary Versalis is expected to ramp up due to the integration of assets acquired in 2018. Finally, we plan to implement a number of initiatives intended to promote the circular economy, as in the case of projects to convert organic waste and plastic waste into feedstock for the production of bio-fuels and bio-chemicals. Finally, management has established a long-term ambition of accomplishing the carbon neutrality leveraging on the following lines of action: i) direct emission reduction, maximizing efficiency in operations and promoting a shift in the energy mix; ii) development of wide forestry initiatives to increase carbon offset; iii) a continuing growth in projects designed to promote the circular economy by recycling waste and by revitalizing decommissioned assets; iv) advances in R&D potentially leading to break-through technologies for example in the fields of the sequestration of CO_2 and of nuclear fusion.

Significant business and portfolio developments

- March 2019 – In Italy, Eni has sucessfully installed and started up the Inertial Sea Wawe Energy Converter (ISWEC) production unit to convert energy generated by waves into electricity.

- March 2019 – Eni announced a new gas discovery, under evaluation, in the Nour exploration license, offshore Egypt.

- March 2019 – Eni farmed out to Qatar Petroleum a 30% stake in the Tarfaya Area, comprising 12 exploration blocks, offshore Morocco. The agreement is subject to the authorization by the Moroccan authorities.

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March 2019 – Eni, following the oil discovery in the Afoxé prospect in December 2018, announced a new oil discovery in the Agogo exploration prospect located in the Block 15/06, offshore Angola.

- March 2019 – Eni farmed out to Qatar Petroleum a 25.5% participating interest in block A5-A, offshore Mozambique. The agreement is subject to the authorization by the Mozambican authorities.. Once the farm-out is completed, Eni will remain operator and its interest in the asset will decrease to 34%.

- February 2019 – The Egyptian Authorities granted Eni two exploration blocks onshore Egypt, in the Western Desert and onshore Nile Delta: South East Siwa (Eni's interest 100%) and West Sherbean (Eni's interest 50%, operator; BP 50%).

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- February 2019 – Finalized the acquisition of a construction-ready solar photovoltaic project near Katherine, in the Northern Territory of the Australia, with an installed capacity of 33.7 MW. The plant will be equipped with a battery storage system and, once into operation, it will avoid around 63,000 tonnes/year of CO2 equivalent emissions.

- January 2019 – Eni signed with Pertamina, the Indonesian state-owned energy company, two agreements to expand the relationship into green refinery and discuss collaboration opportunities in low carbon products and renewable energies development, in particular in waste transformation processes and biomass valorization processes.

- January 2019 – Agreement with Abu Dhabi National Oil Company ("ADNOC") for the acquisition of a 20% interest in the ADNOC Refining company, which owns the refining complexes of Ruwais and Abu Dhabi, with an overall capacity of more than 900 kbbl/d. The total consideration of the deal amounts to $3.3 billion, net of acquired debt and possible price adjustments at the closing date. Additionally, the agreement includes the creation of a joint venture engaged in trading activities, participated by Eni with a 20% interest.

- January 2019 – Eni started a new production well in the Vandumbu field in Block 15/06, offshore Angola, where production commenced in December 2018. The ramp-up is expected to be completed in 2019.

- January 2019 – Vår Energi, the newly constituted entity jointly controlled by Eni and HitecVision, in the Norwegian upstream sector, was awarded thirteen exploration licenses. The company will be operator of 4 licenses and partner of 9 licenses. In 2018 Eni finalized the business combination between Eni Norge and Point Resources, fully controlled by Eni and HitecVision respectively, leading to the creation of Vår Energi, an equity-accounted joint venture (Eni's interest 69.6%) that will develop the activities of the two partners in Norway targeting a production plateau of 250 kboe/d in 2023.

- January 2019 – Eni was awarded seven exploration licenses in onshore/offshore areas in the Middle East: two licenses in Abu Dhabi, one in Oman, one in the Kingdom of Bahrain and three in the Sharjah Emirate.

- December 2018 – Signed a preliminary agreement to acquire a 70% interest and the operatorship of the Oooguruk oil field, in Alaska. Eni already owns the remaining 30% interest. The agreement has been finalized in 2019.

- December 2018 – Significant progress was made towards the final investment decision (FID) of the first phase of the Rovuma LNG project, which contemplates the construction of two LNG trains, each with a capacity of 7.6 mmtonnes/y and obtaining the project financing. After the submission and reviewing of the development plan (PoD) of the project from the authorities, the co-venturers of Area 4 secured long-term agreements for the purchase of LNG volumes. The final investment decision is expected in 2019 and the production is expected to commence in 2024.

- December 2018 – Started up at the Gela site, in Sicily, a pilot plant for recycling and transforming the organic fraction of solid waste produced by households and civil buildings into bio-oil, through proprietary waste to-fuel technology.

- December 2018 – Announced the Merakes East Gas discovery, offshore Indonesia.

- December 2018 – Made the final investment decision at the Merakes Gas Development Project in Indonesia following the approval received by the Minister of Energy of Indonesia. The PoD will leverage the expected synergies with the existing infrastructures of the close Jangkrik gas field producing through a FPU.

- December 2018 – Signed an agreement with Qatar Petroleum for the divestment of a 35% interest in Area 1 discoveries, offshore Mexico, while retaining the operatorship. The agreement is subject to the authorization by the Mexican authorities. The FID project was made at the same time. The start of the pilot project is expected in 2019.

- December 2018 – Farmed out of part of Eni's interest in the Nour license in Egypt to BP (25%) and Mubadala (20%). Eni will retain a 40% interest and the asset operatorship.

- In 2018 Eni, as part of its commitment in circular economy, launched a number of partnerships with some Italian municipalities, Vatican City and multi-utility companies operating in waste treatment and local public transport (in Taranto, Turin, Venice, Rome and in some municipalities of Emilia Romagna) for the exploitation of civil waste and organic raw materials by using them as feedstock to produce energy resources such as biofuels.

- November 2018 – Completed the construction of a photovoltaic plant with a capacity of 10 MW (Eni's share 5 MW), close to the oil field Bir Rebaa Northin Algeria, jointly operated by Sonatrach and Eni.

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- November 2018 – Awarded by the Abu Dhabi National Oil Company (ADNOC) a 25% interest in the Ghasha concession, a large offshore gas project. Eni will retain the technical leadership with expected start-up by the end of 2022 and a projected production plateau at 1.5 bcf/d.

- November 2018 – Versalis and Mazrui Energy Service signed an agreement to establish a joint venture for the commercialization of innovative chemicals for the Oil & Gas industry in the Middle East.

- November 2018 – Eni and Sonangol signed an amendment of Block 15/06 Production Sharing Contract which defined a new block extension.

- November 2018 – Eni and Lukoil signed a farm-out agreement for the transfer of participating interests in three exploration licenses in Mexico's shallow waters. Eni will give Lukoil a 20% stake in the Production Sharing Contracts (PSC) in both Area 10 and Area 14, and will acquire a 40% stake in Lukoil's PSC for Area 12. The agreement is subject to the approval by the Mexican authorities.

- November 2018 – Finalized the acquisition of the Italian Mossi & Ghisolfi Group, engaged in the field of bio-chemicals. The acquired operation includes assets and resources related to development activities, industrialization, licensing of technologies and bio-chemical processes based on the use of renewable resources, especially biomass.

- October 2018 – Eni, Sonatrach and Total signed two agreements which include an exclusive partnership for offshore exploration in Algeria in a virtually unexplored geological province.

- October 2018 – Eni and Sonatrach signed an agreement that will see Eni take a 49% stake in three oil concessions in the onshore North Berkine basin, located in the Algerian desert. Production is expected to start by the end of 2020.

- October 2018 – Eni announced a new oil discovery in the western Barents Sea within license PL 532 in Norway.

- October 2018 – Eni, BP and NOC signed an agreement to resume exploration in Libya. The aim for Eni is to obtain a 42.5% participating interest and the assignment of the operatorship in two onshore and one offshore contractual areas in Libya.

- October 2018 – Eni announced the successful drilling of Cape Vulture appraisal well in the license PL128/PL128D in the Norwegian Sea.

- September 2018 – Eni and GE Renewable Energy signed an agreement for the supply of onshore wind turbines for the Eni-operated Badamsha wind farm project in Kazakhstan, with a target capacity of 50 MW. The FID of the Badamsha project was made in June 2018. The commercial operation date and the connection to the grid is expected by the end of 2019.

- September 2018 – Started up a new elastomer plant in Ferrara, mainly supplying specialties to the automotive industry;

- September 2018 – Eni reached 2.1 bcf/d production target at Zohr field, with the start-up of the fifth treatment unit, in just few months since the first gas (December 2017), the second and third production (April 2018 and May 2018, respectively) and one year before the schedule of the PoD. Expected to reach the production plateau (2.7 bcf/d) in 2019.

- August 2018 – Gas discovery in Egypt at the East Obayed concession, in the Egyptian Western Desert in proximity of producing assets.

- August 2018 – Eni acquired 124 licenses onshore in the Eastern North Slope of Alaska.

- August 2018 – Approved a ten-year extension of the Nile Delta Concession Agreement and a five-year extension of the Ras Qattara Concession Agreement in Egypt.

- August 2018 – Eni was awarded the Nour exploration license in the gas-rich area of the East Nile Delta Basin in the Egyptian territorial waters of the Mediterranean Sea.

- August 2018 – Approved the PoD for the discoveries of Amoca, Miztón and Tecoalli, located in Area 1 (Eni 100%), in Mexico. Early production phase planned in 2019 and full field production will start in 2021.

- July 2018 – Announced another oil discovery in the South West Meleiha license, in the Egyptian Western Desert.

- July 2018 – Started production at the Bahr Essalam Phase 2 project, offshore in Libya.

- July 2018 – Eni started gas production from OCTP Project, deep offshore Ghana. The field will provide 180 mmscf/d for at least 15 years.

- June 2018 – Eni announced a new oil discovery in Block 15/06, in the Kalimba exploration prospect, in Angola’s deep offshore.

- June 2018 – Eni divested to INA its upstream activities offshore Croatia. The transaction closed by year end.

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- June 2018 – Eni finalized the divestment of a 10% stake in the Shorouk concession, offshore Egypt, to Mubadala Petroleum. Expected production plateau of 2.7 bcf/d by the end of 2019 (Eni's interest 50%, Rosneft 30%, BP 10% and Mubadala Petroleum 10%).

- May 2018 – Eni announced an oil discovery in the South West Meleiha license, in the Egyptian Western Desert.

- May 2018 – Eni was awarded a 100% participating interest in the East Ganal Exploration Block in the Kutei Basin in Indonesia.

- April 2018 – Eni and Sonatrach signed agreements to extend their long-dated partnership and to continue their collaboration in the R&D sector. The key feature of the deal was the launch of a large exploration and development program in the Berkine basin.

- March 2018 – Eni was awarded an Exploration & Production license in the Block 28 located in the Cuenca Salina Basin, offshore Mexico, with its partner Lukoil (Eni's interest 75%).

- March 2018 – Eni and Sonangol started oil production at the Ochigufu project, in Block 15/06 in Angola deep offshore. In May, the production ramp-up at the field was completed, allowing the operated production from the Block to stabilize around 150,000 barrels/d and in line with the goal of adding 54,000 barrels/d to the block's production by 2019. The field added 25 KBBL to Eni's current production levels.

- 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 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 acquired 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. 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 were awarded rights to Block 24 located in in the deep waters of the Cuenca Salina Basin in Mexico. Eni will retain the operatorship with a 65% working interest.

- January 2018 – A licensing agreement was signed with Sinopec, a big refining company, for the use of the Eni Slurry proprietary conversion Technology (EST). 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 fully transform refining residues into high-quality light products.

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BUSINESS OVERVIEW

Exploration & Production

Eni's Exploration & Production segment engages in oil and natural gas exploration and field development and production, as well as LNG operations, in 43 countries, including Italy, Libya, Egypt, Norway, the United Kingdom, Angola, Congo, Nigeria, the United States, Kazakhstan, Algeria, Australia, Iraq, Indonesia, Ghana, Mozambique, Oman and the United Arab Emirates. In 2018, Eni average daily production amounted to 1,732 KBOE/d on an available-for-sale basis. As of December 31, 2018, Eni's total proved reserves amounted to 7,153 mmBOE; proved reserves of subsidiaries totaled 6,356 mmBOE; Eni's share of reserves of equity-accounted entities was 797 mmBOE.

"Eni's strategy and short-to-medium term targets in its Exploration & Production segment are disclosed in Item 5 – Management's expectations of operations."

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 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.

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Company guidelines have been reviewed by DeGolyer and MacNaughton (D&M), an independent petroleum engineering company, which stated that those guidelines comply with the SEC rules[1]. D&M has also stated that the Company guidelines provide reasonable interpretation of facts and circumstances in line with generally accepted practices in the industry whenever SEC rules may be less precise. When participating in exploration and production activities operated by 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 30 years of experience in the oil&gas industry and more than 20 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

Eni has its proved reserves audited on a rotational basis by independent oil engineering companies[2]. The description of qualifications of the persons primarily responsible for the reserves audit is included in the third-party audit report[3]. In the preparation of their reports, independent evaluators rely upon information furnished by Eni, without independent verification, with respect to property interests, production, current costs of operations and development, sales agreements, prices and other factual information and data that were accepted as represented by the independent evaluators. These data, equally used by Eni in its internal process, include logs, directional surveys, core and 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 2018, Ryder Scott Company, DeGolyer and MacNaughton and Societé Generale de Surveillance (SGS) provided an independent evaluation of approximately 26% of Eni's total proved reserves at December 31, 2018[4], confirming, as in previous years, the reasonableness of Eni internal evaluation[5].

In the 2016-2018 three-year period, 95% of Eni total proved reserves were subject to an independent evaluation. As at December 31, 2018, the M'Boundi field in Congo was the main Eni property, which did not undergo an independent evaluation in the last three years.

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. In 2018, the SGS company also provided an independent certification.

3

See "Item 19 – Exhibits".

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

5
See "Item 19 – Exhibits".

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Summary of proved oil and gas reserves

The tables below provide a summary of proved oil and gas reserves of the Group companies and its equity-accounted entities by geographic area for the three years ended December 31, 2018, 2017 and 2016.

HYDROCARBONS (mmBOE)	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total reserves
Consolidated subsidiaries1										
Dec. 31, 2018	428	106	1,022	1,246	1,361	1,066	700	302	125	6,356
developed	336	99	582	764	895	925	403	170	87	4,261
undeveloped	92	7	440	482	466	141	297	132	38	2,095
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
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
Equity-accounted entities2										
Dec. 31, 2018		363	14		68			352		797
developed		205	14		17			347		583
undeveloped		158			51			5		214
Dec. 31, 2017			14		75		1	470		560
developed			14		20		1	359		394
undeveloped					55			111		166
Dec. 31, 2016			14		82		2	779		877
developed			14		26		2	349		391
undeveloped					56			430		486
Consolidated subsidiaries and equity accounted entities										
Dec. 31, 2018	428	469	1,036	1,246	1,429	1,066	700	654	125	7,153
developed	336	304	596	764	912	925	403	517	87	4,844
undeveloped	92	165	440	482	517	141	297	137	38	2,309
Dec. 31, 2017	422	525	1,066	1,078	1,511	1,150	428	673	137	6,990
developed	350	360	546	463	876	891	239	535	101	4,361
undeveloped	72	165	520	615	635	259	189	138	36	2,629
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

(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.

(2)
Reserves volumes of the Rest of Europe area, in 2018, are affected by the merger agreement that provided for the sale of the reserves of the former subsidiary Eni Norge as part of the business combination with Point Resources and the acquisition of Eni's share of the reserves held by the combined company Vår Energi, an equity-accounted entity participated by Eni with a 69.6% interest.

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LIQUIDS (mmBBL)	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total reserves
Consolidated subsidiaries										
Dec. 31, 2018	208	48	493	279	718	704	476	252	5	3,183
developed	156	44	317	153	551	587	252	143	5	2,208
undeveloped	52	4	176	126	167	117	224	109		975
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
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
Equity-accounted entities1										
Dec. 31, 2018		297	11		12			37		357
developed		154	11		8			32		205
undeveloped		143			4			5		152
Dec. 31, 2017			12		12			136		160
developed			12		6			25		43
undeveloped					6			111		117
Dec. 31, 2016			13		15			140		168
developed			13		8			22		43
undeveloped					7			118		125
Consolidated subsidiaries and equity accounted entities										
Dec. 31, 2018	208	345	504	279	730	704	476	289	5	3,540
developed	156	198	328	153	559	587	252	175	5	2,413
undeveloped	52	147	176	126	171	117	224	114		1,127
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
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

(1)

Reserves volumes of the Rest of Europe area, in 2018, are affected by the merger agreement that provided for the sale of the reserves of the former subsidiary Eni Norge as part of the business combination with Point Resources and the acquisition of Eni's share of the reserves held by the combined company Vår Energi, an equity-accounted entity participated by Eni with a 69.6% interest.

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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										
Dec. 31, 2018	1,199	320	2,890	5,275	3,506	1,989	1,217	277	651	17,324
developed	980	300	1,447	3,331	1,871	1,846	822	154	452	11,203
undeveloped	219	20	1,443	1,944	1,635	143	395	123	199	6,121
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
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
Equity-accounted entities2										
Dec. 31, 2018		360	14		310			1,716		2,400
developed		276	14		57			1,716		2,063
undeveloped		84			253					337
Dec. 31, 2017			14		349			1,819		2,182
developed			14		83			1,819		1,916
undeveloped					266					266
Dec. 31, 2016			15		368		4	3,484		3,871
developed			15		104		4	1,782		1,905
undeveloped					264			1,702		1,966
Consolidated subsidiaries and equity accounted entities										
Dec. 31, 2018	1,199	680	2,904	5,275	3,816	1,989	1,217	1,993	651	19,724
developed	980	576	1,461	3,331	1,928	1,846	822	1,870	452	13,266
undeveloped	219	104	1,443	1,944	1,888	143	395	123	199	6,458
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
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

(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.

(2)
Reserves volumes of the Rest of Europe area, in 2018, are affected the merger agreement that provided for the sale of the reserves of the former subsidiary Eni Norge as part of the business combination with Point Resources and the acquisition of Eni's share of the reserves held by the combined company Vår Energi, an equity-accounted entity participated by Eni with a 69.6% interest.

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Proved reserves of natural gas liquids are immaterial to the Group operations.

Volumes of oil and natural gas applicable to long-term supply agreements with foreign governments in mineral assets where Eni is operator totaled 148 mmBOE as of December 31, 2018 (178 and 212 mmBOE as of December 31, 2017 and 2016, respectively). Said volumes are not included in reserves volumes shown in the table herein.

	Subsidiaries				Equity-accounted entities	
(mmBOE)	2018	2017	2016	2018	2017	2016
Additions to proved reserves	772	969	1,254	(99)	(285)	(10)
Purchases of minerals-in-place	332	2		363		
Sales of minerals-in-place	(528)	(523)		(1)		
Total additions to proved reserves	576	448	1,254	263	(285)	(10)
Production for the year(a)	(650)	(631)	(616)	(26)	(32)	(28)

(a)
The difference compared to production sold of 625.0 mmBOE (608.6 mmboe in 2016 and 622.3 mmboe in 2017) reflected hydrocarbons volumes of 43.5 mmBOE consumed in operations (32.1 mmBOE in 2016 and 35.2 mmBOE in 2017), changes in inventories and other factors.

	Subsidiaries and equity-accounted entities		
(%)	2018	2017	2016
Proved reserves replacement ratio of subsidiaries and equity-accounted entities, all sources	124	25	193
Proved reserves replacement ratio of subsidiaries and equity-accounted entities, organic	100	103	193

Eni's proved reserves as of December 31, 2018 totaled 7,153 mmBOE (liquids 3,540 mmBBL; natural gas 19,724 BCF). Eni's proved reserves reported an increase of 163 mmBOE, or 2.3%, from December 31, 2017 due to progress made in the year in exploring for and developing new reserves and property acquisitions net of property sales.

Portfolio transactions entailed a net addition of 166 mmBOE and comprised: (i) the purchase of interests in the Concessions Agreements of Lower Zakum (Eni's interest 5%) and Umm Shaif and Nasr (Eni's interest 10%) currently producing offshore Abu Dhabi; (ii) the disposal of a 10% interest in the Zohr gas field and other minor assets in Croatia, Trinidad and Tobago and Indonesia, while the business combination between Eni Norge and Point Resources, leading to the creation of Vår Energi, an equity-accounted joint venture (Eni's interest 69.6%) did not produced any meaningful effects as the reserves divested in connection with the loss of control over the former subsidiary Eni Norge were offset by the acquisition of Eni's interest in the reserves of the equity-accounted combined entity. These net increases were partly offset by production of the year and the de-booking of 106 mmBOE of proved undeveloped reserves at an oil project in Venezuela driven by a deteriorated operational environment in accordance with the applicable SEC rules (for further information see Item 3 – Risk Factor).

All sources additions to proved reserves booked in 2018 were 839 mmBOE; of which 576 mmBOE came from Eni's subsidiaries, while 263 mmBOE from Eni's equity-accounted entities, which included a negative revision due to the de-booking reserves in Venezuela as described above.

Price effects were negative, leading to a downward revision of 38 mmBOE, due to an increased Brent price used in the reserves estimation process up to 71.4 $/BBL in 2018 compared to 54.4 $/BBL in 2017. 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 2018 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,

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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 reported by Eni's subsidiaries and equity-accounted entities was 124% in 2018 (25% in 2017 and 193% in 2016). The organic reserves replacement ratio was 100% (103% in 2017 and 193% in 2016) which excluded sales and purchases of minerals-in-place. The de-booking of reserves at an oil project in Venezuela cut 15 percentage points from the reserves replacement ratio.

The all sources reserves replacement ratio was calculated by dividing additions to proved reserves including sales and purchases of mineral-in-place by total production, each as derived from the tables of changes in proved reserves prepared in accordance with FASB Extractive Activities – Oil & Gas (Topic 932) (see the supplemental oil and gas information in "Item 18 – Consolidated Financial Statements"). The reserves replacement ratio is a measure used by management to assess the extent to which produced reserves in the year are replaced by booked reserves total additions. Management considers the reserve replacement ratio to be an important indicator of the Company's ability to sustain its growth 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 10.6 years as of December 31, 2018, which included reserves of both subsidiaries and equity-accounted entities.

Eni's subsidiaries

Eni's subsidiaries added 576 mmBOE of proved oil and gas reserves in 2018 net of sales and purchase of minerals-in-place. This comprised 239 mmBBL of liquids and 1,838 BCF of natural gas. The breakdown of additions to proved reserves is the following: (i) extensions and discoveries were up by 169 mmBOE mainly due to the final investment decisions made for the operated projects of Area 1 in offshore Mexico, Merakes in Indonesia and Argo and Cassiopea offshore Italy; (ii) revisions of previous estimates were up by 590 mmBOE and mainly derived from progress in development activities at the Zohr and Nidoco NW projects in Egypt and at the Kashagan project in Kazakhstan; (iii) improved recovery were 13 mmBOE mainly reported in Egypt and Iraq; (iv) purchases of mineral-in-place referred to assets in United Arab Emirates as described above; and (v) sales of minerals-in-place referred to the disposal of a 10% stake in the Zohr gas field offshore in Egypt as well as the divest of certain minor assets in Croatia and Trinidad and Tobago. In addition, sales of minerals-in-place included the business combination between Eni Norge AS and Point Resources AS. The merger agreement provided for the sale of the reserves of the former subsidiary Eni Norge as part of the business combination with Point Resources and the acquisition of Eni's share of the reserves held by the combined company Vår Energi, an equity-accounted entity participated by Eni with a 69.6% interest. Further information is provided in "Oil and gas properties, operations and acreage" in Eni's principal oil and gas activities described in Egypt, Norway and the United Arab Emirates, respectively.

Eni's share of equity-accounted entities

All sources additions in Eni's share of equity-accounted entities' proved oil and gas were 263 mmBOE in 2018 and derived mainly from: (i) revisions of previous estimates were down by 99 mmBOE due to the de-booking of 106 mmBOE in Venezuela in accordance with the applicable SEC rules; and (ii) the purchase of minerals-in-place due to the business combination in Norway described above.

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Proved undeveloped reserves

Proved undeveloped reserves as of December 31, 2018 totaled 2,309 mmBOE. At year-end, proved undeveloped reserves of liquids amounted to 1,127 mmBBL, mainly concentrated in Africa and Asia. Proved undeveloped reserves of natural gas amounted to 6,458 BCF, mainly located in Africa. Proved undeveloped reserves of consolidated subsidiaries amounted to 975 mmBBL of liquids and 6,121 BCF of natural gas. The table below provide a summary of changes in total proved undeveloped reserves for 2018.

Subsidiaries and equity-accounted entities (mmBOE)	2018
Proved undeveloped reserves as of December 31, 2017	2,629
Reclassification to proved developed reserves	(777)
Extensions and discoveries	166
Revisions of previous estimates	278
Improved recovery	6
Purchases of minerals-in-place	280
Sales of minerals-in-place	(273)
Proved undeveloped reserves as of December 31, 2018	2,309

In 2018, total proved undeveloped reserves decreased by 320 mmBOE mainly due to progress made in maturing PUD to proved developed (777 mmBOE). Additions to PUD for the year included: (i) extensions and discoveries (up by 166 mmBOE) due to the final investment decision made for the Area 1 project offshore Mexico and the Merakes project in Indonesia; (ii) revisions of previous estimates (up by 278 mmBOE) mainly reported in Egypt due to the development activity of the Zohr project and included the de-booking of reserves in Venezuela as described above; (iii) improved recovery (up by 6 mmBOE) in particular in Iraq. The net effect of portfolio transactions was negligible.

During 2018, Eni matured 777 mmBOE of proved undeveloped reserves to proved developed reserves due to progress in development activities, production start-ups and project revisions. The main reclassifications to proved developed reserves related to the following fields/projects: Zohr (Egypt), Kashagan (Kazakhstan); Bahr Essalam and Wafa (Libya) and Sankofa (Ghana).

In 2018, capital expenditures amounted to approximately €6.2 billion and was made to progress the development of proved undeveloped reserves.

Reserves that remain proved undeveloped for five or more years are a result of several factors that affect the timing of the projects development and execution, such as the complex nature of the development project in adverse and remote locations, physical limitations of infrastructures or plant capacity and contractual limitations that establish production levels. The Company estimates that approximately 0.6 BBOE of proved undeveloped reserves have remained undeveloped for five years or more at the balance sheet date and decreased 0.4 BBOE from 2017 due to the progress in development activities made in Kazakhstan, Iraq and Libya as well as the de-booking of reserves in Venezuela. The proved undeveloped reserves that have remained undeveloped for five years or more at the balance sheet date mainly related to: (i) the Kashagan project in Kazakhstan (0.1 BBOE) due to the complexity of development activities which took more time than initially planned. The project PUD reserves are part of the initial development phase, the production plants and infrastructures of which have been fully commissioned and will support development of the residual project PUD (for further information see "Item 4 – Oil and gas properties, operations and acreage – Kashagan"); (ii the Zubair field in Iraq (0.1 BBOE), where development of PUDs has been conditioned by the drilling of additional production and injection wells to be linked to the production facilities, which were already completed to achieve the full field production plateau of 700 KBBL/d; (iii) certain Libyan gas fields (0.4 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).

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Eni remains strongly committed to put these projects into production in the coming 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 536 mmBOE from producing assets located mainly in Algeria, Australia, Egypt, Ghana, 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, 2018.

Oil and gas production, production prices and production costs

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

In 2018, oil and natural gas production available for sale averaged 1,732 KBOE/d (1,719 KBOE/d in 2017) and increased by approximately 1% from 2017, mainly due to the ramp-ups at fields started up in 2017 mainly in Egypt, Indonesia, Angola, Congo and Ghana, new project start-ups in 2018, higher production at the Kashagan field, Goliat field in Norway and Val d'Agri in Italy, as well as the acquisition of the two Concession Agreements Lower Zakum (5%) and Umm Shaif/Nasr (10%) producing offshore in the United Arab Emirates. These positives were partly offset by negative price effects at PSAs contracts, lower-than-expected produced gas volumes due to the impact of exogenous factors in certain countries, the decline of mature fields as well as certain one-off events (termination of the Intisar contract in Libya and unplanned shutdowns). New field start-ups and ramp-ups of production added an estimated more than 300 KBOE/d of new production.

Liquids production (884 KBBL/d) increased by 32 KBBL/d, or approximately 4% from the full year of 2017. Ramp-ups of the year and the acquisition of two producing concessions in the United Arab Emirates were partly offset by price effect and mature fields decline.

Natural gas production (4,630 mmCF/d) decreased by 104 mmCF/d, or approximately 2% compared to the full year of 2017. Production ramp-ups and start-ups were offset by factors out of management control, particularly a lower-than-expected gas demand in certain geographies.

Sales volumes of oil and gas production sold were 625 mmBOE. The 7 mmBOE difference over production on available-for-sale basis (632 mmBOE in 2018) reflected mainly changes in inventory and other factors. Approximately 70% of liquids production sold (320 mmBBL) was destined to Eni's mid-downstream sectors. About 20% of natural gas production sold (1,665 BCF) was destined to Eni's Gas & Power segment.

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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 country and geographical area of each of the last three fiscal years.

Average daily production available for sale(a)

	2018			2017			2016	
	Liquids (KBBL/d)	Natural gas (mmCF/d)	Hydrocarbons (KBOE/d)	Liquids (KBBL/d)	Natural gas (mmCF/d)	Hydrocarbons (KBOE/d)	Liquids (KBBL/d)	Natura gas (mmC
Eni consolidated subsidiaries								
Italy	60	386	130	53	402	127	47	436
Rest of Europe	113	410	188	102	443	183	109	468
Croatia		10	2		16	3		24
Norway	89	225	131	81	250	126	86	244
United Kingdom	24	175	55	21	177	54	23	200
North Africa	154	1,188	372	158	1,632	457	165	1,486
Algeria	65	35	72	68	35	75	77	44
Libya	86	1,141	295	87	1,585	377	84	1,429
Tunisia	3	12	5	3	12	5	4	13
Egypt	77	1,147	287	72	784	216	76	514
Sub-Saharan Africa	244	346	308	247	328	305	247	353
Angola	111		111	119		119	108	
Congo	65	104	84	63	68	74	71	112
Ghana	15	9	17	8		8		
Nigeria	53	233	96	57	260	104	68	241
Kazakhstan	91	228	133	83	231	126	65	234
Rest of Asia	77	412	152	53	282	105	78	199
China	1		1	2		2	2	
Indonesia	3	315	60	3	161	33	3	39
Iraq	28		28	40		40	64	
Pakistan		97	18		121	22		160
Turkmenistan	6		6	8		8	9	
United Arab Emirates	39		39					
Americas	52	108	72	63	181	96	69	243
Ecuador	12		12	12		12	10	
Trinidad & Tobago		36	6		55	10		70
United States	40	72	54	51	126	74	59	173
Australia and Oceania	2	110	22	2	101	21	3	110

Australia	2	110	22	2	101	21	3	110
	870	4,335	1,664	833	4,384	1,636	859	4,043
Eni's share of equity-accounted entities								
Angola	3	75	17	3	72	17	1	16
Indonesia		2	1	1	9	2	1	15
Tunisia	3	2	3	3	2	3	3	3
Venezuela	8	216	47	12	267	61	14	252
	14	295	68	19	350	83	19	286
Total	884	4,630	1,732	852	4,734	1,719	878	4,329

(a)
It excludes production volumes of hydrocarbons consumed in operations. Said volumes were 119, 97 and 88 KBOE/d in 2018, 2017 and 2016, respectively.

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Annual production available for sale (a)

	2018			2017			2016		
	Liquids (mmBBL)	Natural gas (BCF)	Hydrocarbons (mmBOE)	Liquids (mmBBL)	Natural gas (BCF)	Hydrocarbons (mmBOE)	Liquids (mmBBL)	Natural gas (BCF)	Hy (m
Eni consolidated subsidiaries									
Italy	22	141	48	19	147	46	17	159	47
Rest of Europe	41	150	68	37	162	67	40	171	71
Croatia		4	1		6	1		9	1
Norway	33	82	47	29	91	46	31	89	48
United Kingdom	8	64	20	8	65	20	9	73	22
North Africa	56	434	136	58	596	167	60	544	16
Algeria	24	13	26	25	13	27	28	16	31
Libya	31	417	108	32	579	138	31	523	12
Tunisia	1	4	2	1	4	2	1	5	2
Egypt	28	419	105	26	286	79	28	188	62
Sub-Saharan Africa	89	126	112	90	119	111	91	129	11
Angola	41		41	43		43	40		40
Congo	24	38	30	23	24	27	26	41	33
Ghana	5	3	6	3		3			
Nigeria	19	85	35	21	95	38	25	88	41
Kazakhstan	34	83	49	30	84	46	24	86	39
Rest of Asia	28	150	55	20	103	38	28	73	42
China	1		1	1		1	1		1
Indonesia	1	115	22	1	59	11	1	14	4
Iraq	10		10	15		15	23		23
Pakistan		35	6		44	8		59	11
Turkmenistan	2		2	3		3	3		3
United Arab Emirates	14		14						
Americas	19	40	26	23	66	35	25	89	42
Ecuador	4		4	4		4	4		4
Trinidad & Tobago		13	2		20	4		25	5
United States	15	27	20	19	46	27	21	64	33
Australia and Oceania	1	40	8	1	37	8	1	40	8
Australia	1	40	8	1	37	8	1	40	8
	318	1,583	607	304	1,600	597	314	1,479	58

Eni’s share of equity-accounted entities									
Angola	1	27	6	1	27	6		6	2
Indonesia				1	3	1	1	6	2
Tunisia	1	1	1	1	1	1	1	1	1
Venezuela	3	79	18	4	97	22	5	92	22
	5	107	25	7	128	30	7	105	27
Total	323	1,690	632	311	1,728	627	321	1,584	61

(a)
It excludes production volumes of hydrocarbons consumed in operations. Said volumes were 43.5, 35.2 and 32.1 mmBOE in 2018, 2017 and 2016, respectively.

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Volumes of oil and natural gas purchased under long-term supply contracts with foreign governments or similar entities in properties where Eni acts as producer totaled 54 KBOE/d, 55 KBOE/d and 56 KBOE/d in 2018, 2017 and 2016, respectively.

The tables below provide Eni subsidiaries and its equity-accounted entities' average sales prices per unit of liquids and natural gas by geographical area for each of the last three fiscal years. In addition, Eni subsidiaries and its equity-accounted entities' average production cost per unit of production are provided. With effect from January 1, 2018, with a view to conforming to customary industry practice and in accordance with the applicable SEC rules, Eni has changed the method for calculating the average production cost per barrel-of-oil equivalent. Average production costs no longer include the following items which have previously been included: (i) Royalties and other production taxes; and (ii) Transportation costs relating to the export of the saleable volumes of oil and gas produced, other than the costs incurred to deliver hydrocarbons to a main pipeline, a common carrier, a refinery or a maritime terminal, when unusual physical or operational circumstances exist. A full reconciliation between recomputed average production costs and originally-published amounts by geographic area in 2016 e 2017 is disclosed in the following tables.

Average sales prices and production costs per unit of production

($)	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
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	7.31	6.77	2.79	6.11	8.99	4.98	5.61	7.00	6.44	5.90
Equity-accounted entities										
Oil and condensates, per BBL			17.93				34.95	32.39		30.85
Natural gas, per KCF			1.85				5.92	4.17		4.25
Average production cost, per BOE			5.78				8.19	2.58		2.89
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	6.45	5.81	2.96	4.19	1.87	0.58	3.75	2.35	4.05	3.62

KCF										
Average production cost, per BOE	8.12	8.85	3.08	4.35	9.64	6.68	5.96	8.36	7.11	6.33
Equity-accounted entities										
Oil and condensates, per BBL			17.95		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			5.94		3.45		11.64	1.99		2.71
2018										
Consolidated subsidiaries										
Oil and condensates, per BBL	61.58	64.51	65.95	62.97	68.76	66.78	68.35	57.22	68.72	65.79
Natural gas, per KCF	8.37	7.99	4.97	4.85	2.38	0.77	6.11	2.38	4.80	5.17
Average production cost, per BOE	9.97	8.39	3.16	3.87	10.25	6.53	4.68	10.56	7.09	6.50
Equity-accounted entities										
Oil and condensates, per BBL			17.92		39.48		49.86	54.86		45.19
Natural gas, per KCF			3.58		9.50		9.32	4.28		5.59
Average production cost, per BOE			6.84		6.53		11.03	2.47		3.76

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Full reconciliation between recomputed average production costs and originally-published data

($)	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2017										
Consolidated subsidiaries										
Average production cost, per BOE (as published)	11.43	11.62	4.76	4.51	13.34	9.78	6.39	10.10	7.77	8.45
less: – Royalties	(3.19)		(1.35)		(3.35)		(0.31)		(0.66)	(1.28)
– Transportation costs	(0.12)	(2.77)	(0.33)	(0.16)	(0.35)	(3.10)	(0.12)	(1.74)		(0.84)
Average production cost, per BOE (as recomputed)	8.12	8.85	3.08	4.35	9.64	6.68	5.96	8.36	7.11	6.33
Equity-accounted entities										
Average production cost, per BOE (as published)			10.30		8.05		11.64	9.52		9.31
less: – Royalties			(2.18)		(1.45)			(7.48)		(5.82)
– Transportation costs			(2.18)		(3.15)			(0.05)		(0.78)
Average production cost, per BOE (as recomputed)			5.94		3.45		11.64	1.99		2.71
($)	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2016										
Consolidated subsidiaries										
Average production cost, per BOE (as published)	9.69	9.31	4.33	6.34	12.09	7.58	6.14	8.70	7.08	7.79
less:	(2.28)		(1.21)		(2.73)		(0.45)		(0.64)	(1.09)

– Royalties										
– Transportation costs	(0.10)	(2.54)	(0.33)	(0.23)	(0.37)	(2.60)	(0.08)	(1.70)		(0.80)
Average production cost, per BOE (as recomputed)	7.31	6.77	2.79	6.11	8.99	4.98	5.61	7.00	6.44	5.90
Equity-accounted entities										
Average production cost, per BOE (as published)			9.74				8.19	8.81		8.34
less: – Royalties			(2.38)					(6.08)		(5.24)
– Transportation costs			(1.58)					(0.15)		(0.21)
Average production cost, per BOE (as recomputed)			5.78				8.19	2.58		2.89

Development well activity

In 2018, a total of 209 development wells were drilled (80.2 of which represented Eni’s share) as compared to 178 development wells drilled in 2017 (90.7 of which represented Eni’s share) and 296 development wells drilled in 2016 (118.7 of which represented Eni’s share).

The drilling of 38 development wells (10.6 of which represented Eni’s share) is currently underway.

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, 2018. 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 31 Dec.	
	2018		2017		2016		2018	
(units)	Productive	Dry	Productive	Dry	Productive	Dry	Gross	Net
Italy	3.0		2.6		4.0			
Rest of Europe	2.8	0.3	2.7	0.2	5.6		16.0	1.3
North Africa	9.6	0.5	5.1		6.2	0.7	3.0	1.4
Egypt	30.7		49.7	2.3	32.4	0.5	5.0	2.1
Sub-Saharan Africa	7.3	0.1	8.6		21.2	0.2	6.0	2.5
Kazakhstan	0.9		1.2		4.6		1.0	0.3
Rest of Asia	21.9		15.0	0.2	31.6	0.5	7.0	3.0
Americas	2.3		3.1		9.9	1.3		
Australia and Oceania	0.8							

Total including equity-accounted entities	79.3	0.9	88.0	2.7	115.5	3.2	38.0	10.6

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Exploration well activity

In 2018, a total of 24 new exploratory wells were drilled (15.6 of which represented Eni's share), as compared to 25 exploratory wells drilled in 2017 (15.9 of which represented Eni's share) and 16 exploratory wells drilled in 2016 (10.2 of which represented Eni's share).

The overall commercial success rate was 62% (66% net to Eni) as compared to 60% (52% net to Eni) and 50% (50% net to Eni) in 2017 and 2016, 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, 2018. 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)	
	2018		2017		2016		2018	
(units)	Productive	Dry	Productive	Dry	Productive	Dry	Gross	Net
Italy	1.8					1.0	1.0	0.5
Rest of Europe		0.5	1.2	1.3	0.1	0.4	12.0	3.5
North Africa		0.5	0.5		0.5	1.0	8.0	7.0
Egypt	1.7	1.5	2.5	5.4	5.5	0.8	11.0	8.9
Sub-Saharan Africa	0.4		2.9	0.3	0.1	1.1	31.0	15.1
Kazakhstan							6.0	1.0
Rest of Asia	2.2	2.6				0.9	8.0	2.5
Americas	4.0		0.5			1.0	2.0	1.5
Australia and Oceania							1.0	0.3
Total including equity-accounted entities	10.1	5.1	7.6	7.0	6.2	6.2	80.0	40.3

(1)
Includes temporary suspended wells pending further evaluation.

Oil and gas properties, operations and acreage

In 2018, Eni performed its operations in 43 countries located in five continents. As of December 31, 2018, Eni's mineral right portfolio consisted of 902 exclusive or shared rights of exploration and development activities for a total acreage of 406,505 square kilometers net to Eni (414,918 square kilometers net to Eni as of December 31, 2017). Developed acreage was 28,386 square kilometers and undeveloped acreage was 378,119 square kilometers net to Eni.

In 2018, main changes derived from: (i) new leases mainly in the United Arab Emirates, Indonesia, Lebanon, Morocco, Mexico, Norway and the United States for a total acreage of approximately 31,000 square kilometers; (ii) the total relinquishment of licenses mainly in Australia, China, Egypt, Indonesia, Morocco, Pakistan, Russia, the United Kingdom and Ukraine covering an acreage of approximately 35,000 square kilometers; (iii) interest increase mainly in Angola and Ireland for a total acreage of approximately 2,000 square kilometers; (iv) partial relinquishment in Cyprus, Gabon and Indonesia or interest reduction mainly in Egypt, Norway and Pakistan for approximately 6,400 square kilometers.

In October 2018, Eni submitted to the relevant Authorities of Portugal the documentation required for voluntary release of exploration concessions, with effective date as of January 31, 2019.

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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, 2018. A gross acreage is one in which Eni owns a working interest.

	December 31, 2017	December 31, 2018						
	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	51,206	317	13,757	58,376	72,133	9,409	36,923	46,332
Italy	16,380	140	9,962	8,871	18,833	8,303	6,684	14,987
Rest of Europe	34,826	177	3,795	49,505	53,300	1,106	30,239	31,345
Cyprus	17,967	6		22,790	22,790		17,111	17,111
Croatia	987							
Greenland	1,909	2		4,890	4,890		1,909	1,909
Montenegro	614	1		1,228	1,228		614	614
Norway	2,117	106	2,886	9,630	12,516	492	2,136	2,628
Portugal	3,182	3		4,547	4,547		3,182	3,182
United Kingdom	5,805	57	909	3,719	4,628	614	3,404	4,018
Other Countries	2,245	2		2,701	2,701		1,883	1,883
AFRICA	161,981	261	46,263	258,232	304,495	11,844	153,855	165,699
North Africa	25,797	64	8,846	48,760	57,606	3,640	30,292	33,932
Algeria	1,141	42	3,283	187	3,470	1,124	31	1,155
Libya	13,294	11	1,963	24,673	26,636	958	12,336	13,294
Morocco	9,804	1		23,900	23,900		17,925	17,925
Tunisia	1,558	10	3,600		3,600	1,558		1,558
Egypt	9,192	53	5,423	10,480	15,903	2,018	3,230	5,248
Sub-Saharan Africa	126,992	144	31,994	198,992	230,986	6,186	120,333	126,519
Angola	4,367	58	8,200	13,241	21,441	1,064	4,239	5,303
Congo	1,471	25	1,430	1,320	2,750	843	628	1,471
Gabon	5,283	4		4,107	4,107		4,107	4,107
Ghana	579	3	226	1,127	1,353	100	479	579
Ivory Coast	2,905	3		4,010	4,010		2,905	2,905
Kenya	43,948	6		50,677	50,677		43,948	43,948
Liberia	585							
Mozambique	978	6		3,911	3,911		978	978
Nigeria	7,370	34	22,138	8,631	30,769	4,179	3,543	7,722

South Africa	26,202	1		65,505	65,505		26,202	26,202
Other Countries	33,304	4		46,463	46,463		33,304	33,304
ASIA	184,029	61	13,024	285,289	298,313	3,368	178,046	181,414
Kazakhstan	1,543	7	2,391	3,890	6,281	442	1,101	1,543
Rest of Asia	182,486	54	10,633	281,399	292,032	2,926	176,945	179,871
China	7,154	7	77	5,215	5,292	13	5,215	5,228
India	5,244	1		13,110	13,110		5,244	5,244
Indonesia	22,889	13	2,943	27,230	30,173	1,198	22,571	23,769
Iraq	446	1	1,074		1,074	446		446
Lebanon		2		3,653			1,461	
Myanmar	13,558	4		24,080	24,080		13,558	13,558
Oman	77,146	1		90,760	90,760		77,146	77,146
Pakistan	7,401	12	3,390	11,486	14,876	872	4,914	5,786
Russia	20,862	2		53,930	53,930		17,975	17,975
Timor Leste	1,230	1		1,538	1,538		1,230	1,230
Turkmenistan	180	1	200		200	180		180
United Arab Emirates		3	2,949	5,020	7,969	217	1,255	1,472
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	6,641	252	4,419	12,543	16,962	3,056	6,247	9,303
Ecuador	1,985	1	1,985		1,985	1,985		1,985
Mexico	1,146	8		4,387	4,387		3,000	3,000
Trinidad & Tobago	66							
United States	1,052	230	1,173	1,949	3,122	574	1,617	2,191
Venezuela	1,066	6	1,261	1,543	2,804	497	569	1,066
Other Countries	1,326	7		4,664	4,664		1,061	1,061
AUSTRALIA AND OCEANIA	11,061	11	1,140	4,611	5,751	709	3,048	3,757
Australia	11,061	11	1,140	4,611	5,751	709	3,048	3,757
Total	414,918	902	78,603	619,051	697,654	28,386	378,119	406,505

(a)
Square kilometers.

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

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The table below sets forth, as of December 31, 2018 and by main producing countries in each geographic area, Eni's producing assets, the year in which Eni's activities started, the Eni's participating interest in each assets and whether Eni is operator of the asset.

ITALY	(1926)	Operated	Adriatic and Ionian Sea: Barbara (100%), Cervia/Arianna (100%), Annamaria (100%), Clara NW (51%), Luna (100%), Angela (100%), Hera Lacinia (100%) and Bonaccia (100%)
			Basilicata Region: Val d'Agri (60.77%)
			Sicily Region: Gela (100%), Tresauro (45%), Giaurone (100%), Fiumetto (100%), Prezioso (100%) and Bronte (100%)
REST OF EUROPE			
Norway (a)	(1965)	Operated	Goliat (45.24%), Marulk (13.92%), Balder & Ringhorne (69.6%) and Ringhorne East (53.85%)
		Non-operated	Åsgard (10.31%), Kristin (5.74%), Heidrun (3.60%), Mikkel (10.37%), Tyrihans (4.32%), Morvin (20.88%), Great Ekofisk Area (8.62%), Boyla (13.92%), Brage (8.53%) and Snorre (0.7%)
United Kingdom	(1964)	Operated	Liverpool Bay (100%) and Hewett Area (89.3%)
		Non-operated	Elgin/Franklin (21.87%), Glenelg (8%), J Block (33%), Jasmine (33%) and Jade (7%)
NORTH AFRICA			
Algeria (b)	(1981)	Operated	Blocks 403a/d (from 65% to 100%), Block ROM North (35%), Blocks 401a/402a (55%), Block 403 (50%) and Block 405b (75%)
		Non-operated	Block 404 (12.25%) and Block 208 (12.25%)
Libya (b)	(1959)	Non-operated	Onshore contract areas: Area A (former concession 82 – 50%), Area B (former concession 100/Bu-Attifel and Block NC 125 – 50%), Area E (El Feel – 33.3%), Area F (Block 118 – 50%) and Area D (Block NC 169 – 50%)
			Offshore contract areas: Area C (Bouri – 50%) and Area D (Block NC 41 – 50%)
Tunisia	(1961)	Operated	Maamoura (49%), Baraka (49%), Adam (25%), Oued Zar (50%), Djebel Grouz (50%), MLD (50%) and El Borma (50%)
EGYPT (b)(c)	(1954)	Operated	Shorouk (Zohr – 50%), Nile Delta (Abu Madi West/ Nidoco – 75%), Sinai (Belayim Land, Belayim Marine and Abu Rudeis – 100%), Melehia (76%), North Port Said (Port Fouad – 100%), Temsah (Tuna, Temsah e Denise – 50%), Baltim (50%), Ras Qattara (El Faras e Zarif – 75%), West Abu Gharadig (Raml – 45%), Ashrafi (50%) and North Razzak (100%)
		Non-operated	Ras el Barr (Ha'py and Seth – 50%) and South Ghara (25%)
SUB-SAHARAN AFRICA			
Angola	(1980)	Operated	Blocco 15/06 (36.84%)
		Non-operated	Block 0 (9.8%), Development Areas in the Block 3 and 3/05-A (12%), Development Areas in the Block 14 (20%), Development Area Lianzi in the Blocco 14K/A IMI (10%) and the Development

			Areas in the Block 15 (20%)
Congo	(1968)	Operated	Nené Marine (65%), Litchendjili (65%), Zatchi (55,25%), Loango (42,5%), Ikalou (100%), Djambala (50%), Foukanda (58%), Mwafi (58%), Kitina (52%), Awa Paloukou (90%), M'Boundi (82%), Kouakouala (74.25%), Zingali (100%) and Loufika (100%)
		Non-operated	Pointe-Noire Grand Fond (35%) and Likouala (35%)
Ghana	(2009)	Operated	Offshore Cape Three Points (44.44%)
Nigeria	(1962)	Operated	OMLs 60, 61, 62 and 63 (20%), OML 125 (100%) and OPL 245 (50%)
		Non-operated (d)	OML 118 (12.5%) and service contract OML 116
KAZAKHSTAN (b)	(1992)	Operated (e)	Karachaganak (29.25%)
		Non-operated	Kashagan (16.81%)
REST OF ASIA			
Indonesia	(2001)	Operated	Jangkrik (55%)
Iraq	(2009)	Operated (f)	Zubair (41.6%)
Pakistan	(2000)	Operated	Bhit/Bhadra (40%) and Kadanwari (18.42%)
		Non-operated	Latif (33.3%), Zamzama (17.75%) and Sawan (23.7%)
Turkmenistan	(2008)	Operated	Burun (90%)
United Arab Emirates	(2018)	Non-operated	Lower Zakum (5%) and Umm Shaif and Nasr (10%)
AMERICAS			
United States	(1968)	Operated	Gulf of Mexico: Allegheny (100%), Appaloosa (100%), Pegasus (85%), Longhorn (75%), Devils Towers (75%) and Triton (75%)
			Alaska: Nikaitchuq (100%)
		Non-operated	Gulf of Mexico: Europa (32%), Medusa (25%), Lucius (8,5%), K2 (13.4%), Frontrunner (37.5%) and Heidelberg (12.5%)
			Alaska: Oooguruk (30%)
			Texas: Alliance area (27.5%)
Venezuela	(1998)	Non-operated	Perla (50%), Corocoro (26%) and Junin 5 (40%)

(a)
Assets held by the Vår Energi equity-accounted entities (Eni's interest 69.6%).

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(b)
In certain extractive initiatives, Eni and the host Country agree to assign the operatorship of a given initiative to an incorporated joint venture, a so-called operating company. The operating company in its capacity as the operator is responsible of managing extractive operations. Those operating companies are not controlled by Eni.

(c)
Eni's working interests (and not participating interests) are reported. Those include Eni's share of costs incurred on behalf of the first party accordingly to the terms of PSAs inforce in the Country.

(d)
As partners of SPDC JV, Eni holds a 5% interest in 17 onshore blocks and in 1 conventional offshore block and with a 12.86% in 2 conventional offshore blocks.

(e)
Eni and Shell are co-operators.

(f)
Eni is leading a consortium of partners including international companies and the national oil company Missan Oil.

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, 2018. 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 8,170 (2,836.6 of which represent Eni's share).

Productive oil and gas wells at Dec. 31, 2018(a)

(units)	Oil Wells		Natural gas Wells	
	Gross	Net	Gross	Net
Italy	202.0	157.0	479.0	415.9
Rest of Europe	477.0	86.5	135.0	65.3
North Africa	592.0	242.8	116.0	63.2
Egypt	1,194.0	508.3	147.0	48.3
Sub-Saharan Africa	2,747.0	550.4	181.0	23.0
Kazakhstan	200.0	55.1		
Rest of Asia	955.0	336.7	167.0	62.0
Americas	270.0	132.1	284.0	81.7
Australia and Oceania	3.0	1.2	21.0	7.1
Total including equity-accounted entities	6,640.0	2,070.1	1,530.0	766.5

(a)
Multiple completion wells included above: approximateley 1,445 (450.8 net to Eni).

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 condition 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 contractual arrangements usually take the form of concession agreements or production sharing agreements:

- Concession contracts currently applied mainly in Western countries regulating relationships between States and oil companies with regards to hydrocarbon exploration and production activity. Contractual clauses governing mineral concessions, licenses and exploration permits regulate the access of Eni to hydrocarbon reserves. The company holding the mining concession has an exclusive right on exploration, development and production activities, sustaining all the operational risks and costs related to the exploration and development activities, and it is entitled to the productions realized. As a compensation for mineral concessions, pays royalties on production (which may be in cash or in-kind) and taxes on oil revenues to the state in accordance with local tax legislation. Both exploration and production licenses are granted 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. Proved reserves to which Eni is entitled 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.

In Particular, Eni's exploration and production activities are regulated by concession contracts or a similar scheme mainly in Italy, Ghana, Mozambique, Tunisia, the United Arab Emirates, the United Kingdom, the United States, certain assets in Nigeria, Angola and Australia as well as onshore permits in Pakistan. In Norway, Eni's activities 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.

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- Eni operates under Production Sharing Agreement (PSA) in several of the foreign jurisdictions mainly in African, Middle Eastern, Far Eastern countries. 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 (technologies) 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. 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 Company's share of production volumes and reserves representing the Profit Oil includes the share of hydrocarbons which corresponds to the taxes to be paid, according to the contractual agreement, by the national government on behalf of the Company. As a consequence, the Company has to recognize at the same time an increase in the taxable profit, through the increase of the revenues, and a tax expense. 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 some Service contracts.

Eni's exploration and production activities are regulated by PSA or scheme similar in Algeria, Angola, China, Congo, Egypt, Indonesia, Libya, Mexico, certain assets in Nigeria, Kazakhstan and offshore assets in Pakistan. In addition, Eni's activities are regulated by service contract in one block in Nigeria and in Ecuador. In Australia, the cooperation zone between Timor Leste and Australia (Joint Petroleum Development Area – JPDA) are regulated by PSAs. Development and production activities in Iraq 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 PSA.

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'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 operates 48 onshore and 62 offshore concessions as well as 11 onshore and 9 offshore exploration licenses. In 2018, Italy accounted for 7% of Eni's total worldwide production of oil and natural gas.

Eni's domestic production in 2018 was accounted for 40% in the Adriatic and Ionian Seas, 46% in the Central Southern Apennines and 9% in Sicily.

Development activities in 2018 mainly concerned: (i) maintenance and production optimization, mainly at the offshore fields; and (ii) the progress in development activities at the Argo and Cassiopea operated project (Eni's interest 60%).

In Italy, a new law has been enacted effective February 12, 2019, which requires certain Italian administrative bodies to adopt within eighteen months a plan indented to identify areas that are suitable for carrying out oil and gas activities. See "Risk Factors – Oil and gas activity may be subject to increasingly high levels of regulations throughout the world, which may impact our extraction activities and the recoverability of reserves". Management is not currently in the position to make a reliable and fair estimation of future impacts of the new law provisions on the recoverability of the volumes of proved reserves booked in Italy and the associated future cash flows. However, based on the review of all facts and circumstances and on the current knowledge of the matter, management does not expects any material impacts on the Group future results of operations and cash flow.

Rest of Europe

Eni's operations in the Rest of Europe are mainly conducted in Norway and the United Kingdom. In 2018, the Rest of Europe accounted for 11% of Eni's total worldwide production of oil and natural gas.

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Croatia. In 2018, Eni divested exploration and production activities in the Country.

Norway. In December 2018, it was finalized the business combination between Point Resources AS and Eni Norge AS, fully-owned by HitecVision and Eni respectively, with the creation of Vår Energi AS, an equity-accounted joint venture. The exchange rate of shares was established so that Eni and the Point Reources shareholders would retain participation interests of 69.6% and 30.4% respectively, in the combined entity. The governance of the new entity is designed to establish joint control of the two shareholders over the combined entity. Therefore, effective at the closing, Eni derecognized the assets and liabilities of Eni Norge and recognized the fair value of the interest retained in the merged company that will be equity-accounted going forward.

The transaction intends to strengthen Eni's position in the Country by integrating the asset portfolios of the merged companies and extracting synergies by combining different know-how, skills and resources. Eni gained access to the portfolio of Point Resources, which included producing assets such as the Balder & Ringhorne, Ringhorne East, Boyla, Brage and Snorre fields and a number of development options. The portfolio of the combined company currently comprises seventeen producing oil and gas fields with a wide geographical reach, from the Barents Sea to the North Sea.

Eni retains a first offer right in case the Norwegian private equity funds, managed by HitecVision, decide to divest their interest in the venture.

In 2019, Vår Energi was awarded 13 exploration licenses: (i) the operatorship in two licenses in the North Sea and two licenses in the Barents Sea; and (ii) the interest in five licenses in the North Sea and four licenses in the Norway Sea.

Development activities mainly concerned: (i) the Trestakk project (Eni's interest 5.5%) with start-up expected in 2019; and (ii) the Johan Castberg project in the PL 532 license (Eni's interest 20.88%), which was sanctioned in June 2018. Start-up is expected in 2022

Exploration activity yielded positive results with: (i) delineation well of the Cape Vulture oil and gas discovery in the PL 128/128D license (Eni's interest 8%), nearby to the production facilities of the Norne field (Eni's interest 4.8%); (ii) an oil discovery in the PL 532 license, nearby the Johan Castberg project; (iii) the Goliat West oil well in the PL 229 (Eni's interest 45.24%); and (iv) an oil and gas discovery in the PL 869 which is participated by Vår Energi AS with a 20% interest.

United Kingdom. Development activities mainly concerned: ((i) two infilling wells drilled in Elgin Franklin fields (Eni's interest 21.87%), one in production from September and the second one to be completed in 2019; (ii) two infilling wells in Joanne and Jasmine fields (Eni's interest 33%), both of them in production since May and September, moreover a workover activity started and was completed at the beginning of 2019.

North Africa

Eni's operations in North Africa are conducted in Algeria, Libya, Morocco and Tunisia. In 2018, North Africa accounted for 22% of Eni's total worldwide production of oil and natural gas.

Algeria. In April 2018, Eni signed a framework agreement with Sonatrach to revamp exploration and development activities in the Berkine area. The agreement covered the following items: (i) in July 2018 defined an agreement for upgrading existing facilities of the BRN fields in the Block 403 (Eni operator with a 50% interest) and of the MLE fields in the Block 405b (Eni operator with a 75% interest) leveraging on synergies with the new forthcoming facilities. The agreement also includes the construction of pipeline to link the BRN fields with the MLE assets targeting to transform the area in a gas hub; and (ii) in October 2018 signed an agreement to assign to Eni a 49% interest in the Sif Fatima II, Zemlet El Arbi and Ourhoud II concessions, in the North Berkine area. Management plans an exploration campaign and fast-track development activities. Start-up is expected in the third quarter of 2019 leveraging on the completion of the BRN-MLE pipeline that will link the BRN associated gas as well as associated gas and condensates of the Berkine North development project to the MLE treatment facilities. In addition, Eni and Total signed two partnership agreements for an exploration campaign in the offshore Algeria. In December 2018, two exploration permits were assigned to launch a seismic data acquisition in 2019.

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Development activities concerned: (i) production optimization at the ROM North (Eni's interest 35%) and ROD (Eni's interest 55%) operated fields as well as in the non-operated Block 404 (Eni's interest 12.25%); (ii) drilling activities in the Block 405b at the CAFC Oil and MLE projects as well as upgrading activity of existing treatment facilities; and (iii) progress in the development program of the El Merk field in the Block 208 (Eni's interest 12.25%) with the drilling of production and water injection wells.

Libya. In recent years, Eni's petroleum activities in Libya have been negatively affected by the unstable political and social framework of the Country. Currently, Libya represents approximately 17% of the Group's total production; although this proportion is forecasted to decrease in the medium term, the Libya situation remain an area of issue. For further information on this matter, see "Item 3 – Risk factors – Political considerations".

The rights to produce of Eni's assets in Libya will expire in 2038 for Contract Area C, in 2041 for Contract Area E, in 2042 for Contract Area A and B as well as in 2043 for Contract Area D production

In 2018, Eni finalized an agreement with NOC oil state company and BP to award a 42.5% interest and the operatorship in the BP contractual areas, in particular in the onshore Area A and Area B and in the offshore Area C. The agreement provides for a revamp exploration and development activities in the Country leveraging on Eni's facilities existing in the areas.

During the year, development activities concerned: (i) production start-up of the Bahr Essalam Phase 2 offshore project (Eni's interest 50%) where the planned activities progressed and the completion is expected in the second quarter of 2019. The development plan provided for drilling ten wells, out of which seven were completed and started up in 2018, as well as upgrading the existing facilities to increase production capacity; (ii) upgrading of treatment plants at the Mellitah area (Eni's interest 50%) and at the Sabratha platform (Eni's interest 50%); and (iii) a production optimization plan at the Wafa field. The activity provided for drilling additional wells and the construction of new compression units. In particular, the infilling wells campaign started in 2018: a first gas well was completed in November 2018 and a second one in March 2019. The project is expected to be completed in 2019.

Morocco. In March 2019, Eni signed an agreement to divest a 30% interest in the Tarfaya Offshore Shallow exploration license to Qatar Petroleum, retaining the operatorship of the permit with a 45% interest. The agreement is subject to approval by relevant Authorities.

Tunisia. Development activities concerned production optimization at the producing concessions to mitigate mature fields declines.

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Egypt

In 2018, Egypt accounted for 16% of Eni's total worldwide production of oil and natural gas.

In February 2019, Eni was awarded two onshore exploration blocks: (i) a 100% interest in the South East Siwa block in the western desert nearby to the South West Meleiha concession (Eni's interest 100%); and (ii) the operatorship with a 50% interest in the West Sherbean block in the onshore Nile Delta nearby to the operated Nooros producing fields (Eni's interest 75%).

In June 2018, Eni completed the disposal of a 10% interest of the Zohr project (Eni's interest 50%) to Mubadala Petroleum, for a cash consideration of $934 million.

In August 2018, Egyptian Authority approved the following agreements: (i) Eni was awarded an 85% interest in the Nour exploration license in the eastern offshore Nile Delta. In December 2018, Eni divested a 20% and 25% interest of Nour license to Mubadala Petroleum and BP, respectively. Currently Eni holds 40% interest; (ii) ten years extension from 2021 of the Nile Delta concession (Eni's interest 75%) which includes Abu Madi West concession with Nooros producing field; (iii) an extension of exploration campaign in the El Qar'a permit (Enis' interest 75%), which is located in the Great Nooros producing area; (iv) five years extension of the Ras Qattara concession (Eni's interest 75%) in the western desert; and (v) an extension of the Faramid development lease (Enis' interest 100%).

In September 2018, the Zohr project achieved the targeted production plateau of 365 KBOE/d (110 KBOE/d net to Eni) with the completion of the drilling activities and the construction and commissioning of the planned four gas treatment units onshore in addition to the one started at the end of 2017, which increased available treatment capacity to more than 2.1 BCF/d. Management plans to step up the production plateau to 3.2 BCF/d during 2019 by building and commissioning other three gas treatment units and by drilling three additional production wells to reach 13 production wells.

As of December 31, 2018, the aggregate development costs incurred by Eni for the Zohr project capitalized in the financial statements amounted to $4.3 billion (€3.8 billion at the EUR/USD exchange rate of December 31, 2018). The planned capital expenditures to support continuing production ramp-up at the Zohr field in the next four-year period will be financed through net cash provided by operating activities at the Eni Brent marker scenario.
As of December 31, 2018, Eni's proved reserves booked for the Zohr field amounted to 782 mmBOE. The Zohr proved reserves, both developed and undeveloped, are related to the project phase 1 only.
Development activities at other Eni's fields in Egypt concerned: (i) the Baltim South West project (Eni operator with a 55% interest) in the offshore of the Country. The project sanctioned in 2018 and start-up is expected during 2019; (ii) the completion and start-up of two additional productive wells of the Nooros field (Eni operator with a 75% interest) and the construction of a pipeline for transporting gas to the treatment plan of El Gamil. The completion of the activities is expected in 2019; and (iii) infilling activities and production optimization in the operated Sinai (Eni's interest 100%), Meleiha (Eni's interest 76%) and Ras Qattara (Eni's interest 75%) concessions.

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Exploration activities yielded positive results with: (i) the Faramid-S1X gas well in the East Obayed concession (Eni's interest 100%); (ii) the A-2X and B1-X oil discoveries and the A-1X gas and condensates discovery in the South West Meleiha concession; and (iii) the Nour-1 gas well in the Nour exploration license.

Sub-Saharan Africa

Eni's operations in Sub-Saharan Africa are conducted mainly in Angola, Congo, Ghana, Mozambique and Nigeria. In 2018, Sub-Saharan Africa accounted for 19% of Eni's total worldwide production of oil and natural gas.

Angola. In November 2018, Eni signed an amendment of the Block 15/06 PSA contract (Eni operator with a 36.84% interest) that defines an additional exploration acreage in the western area of the block.

Development activities mainly concerned the two producing projects in the Block 15/06. In particular, activity of the West Hub project included: (i) production ramp-up of the Ochigufu field was achieved with a production plateau of 25 KBBL/d; and (ii) production start-up of the Vandumbu field. In the East Hub project development activities concerned: (i) production start-up of UM8 field with the linkage to FPSO exisisting in the area; (ii) upgrading of certain production facilities; and (iii) the Cabaça North & Cabaça South-East UM4/5 projects were sanctioned; the development plan foreseen the drilling of three productive wells, two water injection wells and the connection to the existing production facilities in the area. Start-up is expected in 2021.

Planned drilling activities were completed at the Mafumeira Sul producing field in the Block 0 (Eni's interest 9.8%).

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 2018 production net to Eni averaged approximately 20 KBOE/d.

Exploration activities have given positive results with the Kalimba and Afoxé oil discoveries in the East Hub project area as well as the Agogo oil discovery in the West Hub project area.

Congo. Development activity carried out in 2018 related to: (i) the Nené Marine Phase 2A producing project in the Marine XII block (Eni operator with a 65% interest) with the completion of drilling activities and the installation of a sealine for the connection to the Litchendjili field production platform in the Marine XII block; and (ii) the completion of engineering activities of the Nené Marine phase 2B project. The project was sanctioned in December 2018.

Ghana. In 2018, the non-associated gas production started up at the operated Offshore Cape Three Points (OCTP) project (Eni's interest 44.44%). The gas production is sent to an onshore treatment plant to feed the national grid.

The Offshore Cape Three Points license expires in 2036.

Eni also operates the offshore exploration license Cape Three Points Block 4 (Eni's interest 42.47%).

Mozambique. Eni has been present in Mozambique since 2006, following the award of the exploration license relating to gas-rich Area 4 Offshore of the Rovuma Block.

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 important Coral gas discovery, which falls entirely in Area 4.

During the exploration period, which expired in 2015, six Discovery Areas (DA) were identified. Mozambique Decree Law 02/2014 provides that individual 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 the Government of Mozambique entitles the Concessionaires to develop and to produce in a term of 30 years, with an extension option pursuant to the terms of the Area 4 EPCC and the applicable Petroleum Law.

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Following two separate transactions occurred respectively in 2013 and in 2017, Eni divested to CNPC and Exxon Mobil indirect interests of 20% and 25% respectively in the discoveries of Area 4, by diluting its participating interest in Mozambique Rovuma Venture SpA, the operator of Area 4. Past transactions, Eni retains a 25% indirect interest in the Area 4 concession. The other concessionaires of Area 4 are the state-owned oil company ENH, Galp and Kogas, each with a 10% working interest.

Development activities continued at the Coral South Floating LNG project during 2018, which is operated by Eni. The LNG produced will be sold by the Area 4 Concessionaires to BP under a long-term contract for a period of twenty years, with an option for an additional ten-year term.

Pre-Development activities progressed at the Mamba Complex discoveries where Eni is operator of the upstream development phase and Exxon Mobil leads the construction and operation phase of natural gas liquefaction facilities onshore. The Mozambique authorities expressed their intent to unitize the reservoir that straddles Area 4 and Area 1. In the meantime, pending a final determination of the unitization, the Concessionaires of Area 4 are entitled to develop part of the reserves contained in the reservoir that straddles the two areas on condition that the two operators will coordinate their activities.

In this context, the Area 4 Concessionaire progressed activities to made the final investment decision (FID) for the Rovuma LNG project, which provides the construction of two onshore LNG trains with capacity of approximately 7.6 mmtonnes/y each, feed by 24 subsea wells, the gas treatment, the liquefaction, the storage and the export of LNG. In July 2018, the plan of development (PoD) was submitted to the relevant Authorities for their initial review. The activities progressed with the finalization of the PoD, of preliminary long-term agreements for the purchase of LNG volumes and the project financing. The Final Investment Decision is expected in 2019 with start-up in 2024.

In October 2018 Eni signed the contract for the exploration and development rights of the offshore block A5-A, in the deep offshore of Zambesi. Eni was awarded the operatorship of the block with a 59.5% interest. In March 2019, Eni signed a farm out agreement with Qatar Petroleum to divest a 25.5% interest in the block. The transaction is subjected by approval of the relevant Authority.

Nigeria. Development activities mainly included: (i) workover and rigless activities to support current production as well as maintenance and restoration of damaged facilities due to sabotage and bunkering in the operated OML60, 61, 62 and 63 blocks (Eni’s interest 20%); (ii) drilling activities to increase production and workover activities to mitigate mature field decline in the OML 118 block (Eni’s interest 12.5%) and in the operated OML 125 block in the Abo field (Eni’s interest 100%); and (iii) associated gas program of Forkados Yokri Integrated Project in the OML 43 block (Eni’s interest 5%) as well as Gbaran phase 2A/2B and SSAGS project in the OML 28 block (Eni’s interest 5%). Gas production will be sold to the local market.

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. Natural gas supplies to the plant are currently provided under a gas supply agreements from the SPDC JV (Eni’s interest 5%), TEPNG JV and the NAOC JV (Eni’s interest 20%). In 2018, 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.

Exploration activities yielded positive results with the EPU-05 deep offshore gas discovery in the Gbaran-Kolo Creek-Epu area (Eni’s interest 5%).

In the exploration phase Eni operates offshore OML 134 (Eni’s interest 100%), 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.

The acquisition of the OPL 245 property made by Eni in 2011 is the subject of certain judicial proceedings describe in “Item 18 – consolidated financial statement – Note 27”.

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Kazakhstan

Eni’s operations in Kazakhstan mainly regards the Kashagan and the Karachaganak fields. In 2018, Kazakhstan accounted for 8% of Eni’s total worldwide production of oil and natural gas.

Kashagan. Eni holds a 16.81% working interest in the North Caspian Sea Production Sharing Agreement (NCSPSA). The NCSPSA defines terms and conditions for the exploration and development of the Kashagan field, which was discovered in the Northern section of the contractual area in the year 2000 over an 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%.

In 2018, production of the Kashagan field averaged 47 KBBL/d net to Eni of liquids and 58 mmCF/d net to Eni of natural gas. The treated gas is delivered to the national gas marketing and transportation company (KazTransGas), and the remaining volumes is utilized as fuel gas for internal use. The remaining untreated gas volumes (approximately 30%) is re-injected in the reservoir. The liquid production is stabilized at Bolashak facilities and exported to Western markets through the Caspian Pipeline Consortium (Eni’s interest 2%) and the Atyrau-Samara pipeline.

In 2019, Experimental Program development of the field is expected to lead to plateau oil production capacity of about 370 KBBL/d, on a 100% basis. Additional phases of development are being studied, which contemplate increasing gas injection capacity, the conversion of production wells into injection wells and the upgrading of the

existing facilities.
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, 2018, Eni's proved reserves booked for the Kashagan field amounted to 614 mmBOE, slightly decreased from 620 mmBOE in 2017.
As of December 31, 2018, the aggregate costs incurred by Eni for the Kashagan project capitalized in the financial statements amounted to $9.9 billion (€8.6 billion at the EUR/USD exchange rate of December 31, 2018). This capitalized amount included: (i) $7.3 billion relating to expenditure incurred by Eni for the development of the oil field; and (ii) $2.6 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.

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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 2018, production of the Karachaganak field averaged 44 KBBL/d net to Eni of liquids and 170 mmCF/d net to Eni of natural gas. This field is developed by producing liquids from the deeper layers of the reservoir. The gas is marketed (about 50%) 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 95% of liquid production are stabilized at the Karachaganak Processing Complex (KPC) 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 was marketed at the Russian terminal in Orenburg until September 2018, when the purchase agreement expired.

Within the gas treatment expansion projects of the Karachaganak field, the Karachaganak Process Center Debottlenecking project was sanctioned. Activity progressed with completion expected in 2020. Additional re-injection capacity will be ensured by installing a new re-injection facility in addition to the existing ones.

As of December 31, 2018, Eni's proved reserves booked for the Karachaganak field amounted to 452 mmBOE, reporting a decrease of 78 mmBOE from 2017 mainly due to an increased marker Brent price used in the reserves estimation process.

Rest of Asia

In 2018, Eni's operations in the Rest of Asia accounted for 9% of its total worldwide production of oil and natural gas.

Bahrain. In January 2019, Eni signed a Memorandum of Understanding with the National Oil and Gas Authority of the Kingdom of Bahrain (NOGA). The agreement includes an exploration program for the offshore Block 1.

China. Eni has been present in China since 1984 with activities located in the South China Sea.

In 2018, hydrocarbons were produced from the offshore Blocks 16/19 through 3 platforms connected to an FPSO.

Indonesia. Activities are concentrated in the offshore of East Kalimantan, offshore Sumatra, and offshore and onshore of West Timor and West Papua; in total, Eni holds interests in 13 blocks.

In May 2018, Eni was awarded a 100% interest in the East Ganal exploration block in the deep offshore Kutei area nearby the operated Muara Bakau block (Eni's interest 55%).

In 2018, within the portfolio rationalization, Eni divested entire interest in the Sanga Sanga permit.

Development activities concerned the offshore Merakes gas project in the operated East Sepinggan block (Eni's interest 85%). In December 2018, the development plan was sanctioned by relevant Authorities. The project provides for the drilling of five subsea wells, which will be linked to the Floating Production Unit (FPU) of the Jangkrik producing fields (Eni operator with a 55% interest). 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 or will be sold on a spot basis in the domestic market. Start-up is expected in 2020.

Exploration activities yielded positive results with the Merakes East discovery in the operated East Sepinggan block.

Iraq. Development activities concerned the execution of an additional development phase of the ERP (Enhanced Redevelopment Plan) for the Zubair field, to achieve a production plateau of 700 KBBL/d. This phase also contemplates utilization of the associated gas for power generation. The 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.

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Lebanon. In February 2018, Eni signed two Exploration and Production Agreements (EPA) with the Republic of Lebanon including Blocks 4 and 9, located in the deep-offshore Lebanon. Eni owns a participating interest of 40% in each block.

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).

Oman. Eni has been present in Oman since 2017. Eni operates the Block 52, located offshore Oman. In January 2018, the relevant Authorities of the country approved the farm out agreement signed in 2017 with the Qatar Petroleum oil company. Eni retains the operatorship of the block with a 55% interest.

In January 2019, Eni was awarded the exploration Block 47 and signed a Head of Agreement for the exploration Block 77, located onshore Oman. Eni will operate both blocks with a 90% interest and 50% interest, respectively.

Pakistan. In 2018, development activities concerned production optimization through drilling activities of new wells, optimization of onshore existing facilities and rigless activity of productive wells to mitigate the natural fields production decline.

Russia. Eni is present in Russia through two joint ventures with Rosneft, which retain the exploration licenses relating to the Fedynsky and the Central Barents areas respectively (Eni's interest 33.33%) in the Russian Barents Sea.

In July 2018, following unsuccessful exploration activity, Eni relinquished the Western Chernomorsky license (Eni's interest 33.33%) in the Black Sea.

There are no ongoing, nor planned exploration activities in the Country.

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

Turkmenistan. Activities are focused on the onshore Nebit Dag Area (Eni operator with a 90% interest) in the Western part of the country. The license expires in 2032.

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.

Drilling activities of new wells and workover program represent main activities currently performed in the area to mitigate the natural field production declines.

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.

In November 2018, Eni was awarded a 25% interest in the Ghasha offshore concession with duration of 40 years. The concession includes the Hail, Ghasha and Dalma gas discoveries and certain offshore fields in the Al Dhafra area. Production start-up is expected in 2022.

In January 2019, Eni was awarded the operatorship of the Block 1 and 2 with a 70% interest, located offshore Abu Dhabi. The exploration commitment for the first phase consists in exploration studies for the Block 1 and the drilling of two exploration wells and two appraisal wells in the Block 2.

In January 2019 Eni was awarded three onshore exploration concessions in the Emirate of Sharjah: (i) the operatorship with a 75% interest in the concession Area A and C; and (ii) a 50% interest in the concession Area B. The exploration commitment of first phase includes the drilling of one exploration well and exploration studies in concessions Area A and B as well as exploration studies in Area C.

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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 2018, Eni's operations in the Americas area accounted for 7% of its total worldwide production of oil and natural gas.

Ecuador. Eni has been present in Ecuador since 1988. Operations are performed in Block 10 (Eni's interest 100%) located in the Oriente Basin, in the Amazon forest.

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. Eni is planning to divest its entire working interest in Block 10.

Mexico. Eni has been present in Mexico since 2015. Eni's activities are concentrated in the Gulf of Mexico. Eni is operator of: (i) the offshore Area 1 license (Eni's interest 100%) where the development activities of the Amoca, Miztón and Tecoalli discoveries progressed aiming at starting production in 2019; and (ii) the Area 10 (Eni's interest 100%), the Area 14 (Eni's interest 60%) and the Area 7 (Eni's interest 45%) exploration licenses located in the Sureste basin.

Furthermore, in 2018, Eni was awarded the operatorship with a 65% interest of the Area 24 license and with 75% of the Area 28 license.

Exploration and production activities in Mexico are regulated by PSA and concession contract for the Area 24 license.

In 2018, Eni signed an agreement with Lukoil to swap interests in three exploration licenses. Based on the agreement which approval is to be ratified by local Authorities, Eni will divest its 20% interest in Area 10 and Area 14 licenses and will purchase a 40% interest in Area 12 license operated by Lukoil.

In July 2018 the Plan of Development (PoD) for the Amoca, Mitzón and Tecoalli discoveries was approved by the Mexican Authorities. The phased approach for the development plan includes an early production start-up in 2019 through the installation of a production platform and the realization of facilities to connect the platform to an onshore existing treatment plant, with a production of 8 KBBL/d. The full field development envisages a phased installation of three additional platforms and a FPSO, which will increase the production capacity up to 90 KBBL/d in 2021. In December 2018, Eni agreed to divest its 35% interest of the Area 1 to Qatar Petroleum Company. The agreement is awaiting approval from the local Authorities.

Trinidad and Tobago. In 2018, Eni divested its entire interest of upstream activities in the Country.

United States. Eni holds interests in 62 exploration and production blocks in the Gulf of Mexico, of which 26 are operated by Eni.

Development activities concerned the Lucius Subsequent Development (Eni's interest 8.5%) with the drilling and completion of three submarine productive wells, which will be linked to the production platform of the Lucius field and upgrading of existing facilities.

To achieve the highest safety standards of its operations, Eni is 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".

In August 2018, Eni was awarded a 100% interest of 124 licenses in Alaska. Eni currently performed its activity in 166 exploration and development blocks in Alaska.

In December 2018, Eni signed an agreement to purchase of 70% interest and the operatorship of the Ooguruk field, where Eni already holds 30% interest. The agreement has been finalized in 2019.

Venezuela. Eni's activity is located in the Gulf of Venezuela and Gulf of Paria and onshore in the Orinoco Oil Belt.

In 2018, Eni's production of oil and natural gas averaged 47 KBOE/d and accounted for approximately 3% of Eni's total production.

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 2018, 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. Activities are focused on offshore fields.

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 the operatorship of NT/RL7 (Eni's interest 65%). In addition, Eni holds interest in 4 exploration licenses, of which 1 in the JPDA.

Capital expenditures

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

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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. There were not any outstanding trading receivables towards Iran's national oil companies as of December 31, 2018. In 2018, Eni made payments in the region of $0.6 million to the Iranian Social Security Organization in connection to health and social security insurance for which Eni retains at December 31, 2018 a residual payable amounting to approximately $5 million, which will be settled upon de-registration of our local branch.

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 the activities of electricity generation. In 2018, Eni's worldwide sales of natural gas amounted to 76.71 BCM. Sales in Italy amounted to 39.03 BCM, while sales in European markets were 29.42 BCM that included 3.42 BCM of gas sold to certain importers to Italy.

The business results of operations in 2018 and its strategy are described in "Item 5 – 2016 – 2018 Group results of operations" and "Item 5 – Management's expectations of operations."

Supply of natural gas

In 2018, Eni's total supply of natural gas was 74.15 BCM, down by 4.13 BCM, or 5.3% from 2017. Gas volumes supplied outside Italy (68.82 BCM from consolidated companies), imported in Italy or sold outside Italy, represented approximately 93% of total supplies, down by 4.41 BCM, or 6% compared to the previous year, due to lower volumes purchased in Russia (down by 1.85 BCM), in the Netherlands (down by 1.25 BCM) in Algeria (down by 1.16 BCM) and in Norway (down by 0.73) partially offset by higher purchases in Indonesia (up by 2.32 BCM) and in Qatar (up by 0.20 BCM).

Supplies in Italy (5.33 BCM) increased by 5.5% from 2017 due to higher equity production.

In 2018, main gas volumes from equity production derived from: (i) Italian gas fields (3.9 BCM); (ii) certain Eni fields located in the British and Norwegian sections of the North Sea (2.6 BCM); (iii) Indonesia (1.6 BCM); (iv) Libyan fields (1.4 BCM); (v) the United States (0.3 BCM).

Supplied gas volumes from equity production were approximately 9.9 BCM representing 13% of total volumes available for sale.

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

Natural gas supply	2018	2017	2016
	(BCM)		
Italy	5.33	5.05	6.00
Outside Italy	68.82	73.23	76.64
Russia	26.24	28.09	27.99
Algeria (including LNG)	12.02	13.18	12.90
Libya	4.55	4.76	4.87
the Netherlands	3.95	5.20	9.60
Norway	6.75	7.48	8.18
the United Kingdom	2.21	2.36	2.08
Indonesia (LNG)	3.06	0.74	
Qatar (LNG)	2.56	2.36	3.28
Other supplies of natural gas	5.52	6.75	5.83
Other supplies of LNG	1.96	2.31	1.91
Total supplies of subsidiaries	74.15	78.28	82.64
Withdrawals from (input to) storage	0.08	0.31	1.40
Network losses, measurement differences and other changes	(0.18)	(0.45)	(0.21)
Volumes available for sale of Eni's subsidiaries	74.05	78.14	83.83
Volumes available for sale of Eni's affiliates	2.66	2.69	2.48
Total volumes available for sale	76.71	80.83	86.31

Sales of natural gas

Eni is selling gas to wholesale and retail markets in Italy and in a number of European countries. The wholesale market includes sales to large accounts (industrials and thermoelectric utilities) and on European spot markets. The retail segment includes sales to residential customers (households and larger accounts like hospitals, schools, office buildings) and small and medium-sized businesses located in urban areas. The Company has grown the combined offer of gas and electricity to retail customers to maximize cross-selling opportunities and cost synergies.

In 2018, natural gas sales amounted to 76.71 BCM (including Eni's own consumption, Eni's share of sales made by equity-accounted entities), representing a decrease of 4.12 BCM, or 5.1% from the previous year. Sales in Italy (39.03 BCM) increased by 4.3% from 2017. Higher sales to spot market and volumes sold to wholesalers and industries were partly offset by lower sales to thermoelectrical and residential segments. Sales in the European markets amounted to 26 BCM, a decrease of 24.3% or 8.34 BCM from 2017.

Sales to long-term buyers were down by 12.1% compared to the previous year due to the shorter availability of Libyan output. Sales in the Extra European markets (8.26 BCM) increased by 3.09 BCM or 59.8% due to higher LNG sales in Japan, Pakistan, China and Taiwan, partly offset by higher volumes sold in South Korea and India.

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

Natural gas sales by entities	2018	2017	2016
	(BCM)		
Total sales of subsidiaries	73.70	77.52	83.34
Italy (including own consumption)	39.03	37.43	38.43
Rest of Europe	27.58	36.10	40.52
Outside Europe	7.09	3.99	4.39
Total sales of Eni's affiliates (Eni's share)	3.01	3.31	2.97
Italy			
Rest of Europe	1.84	2.13	1.91
Outside Europe	1.17	1.18	1.06
Worldwide gas sales	76.71	80.83	86.31

Natural gas sales by market	2018	2017	2016
	(BCM)		
ITALY	39.03	37.43	38.43
Wholesalers	9.15	8.36	7.93
Italian gas exchange and spot markets	12.49	10.81	12.98
Industries	4.79	4.42	4.54
Medium-sized enterprises and services	0.79	0.93	1.72
Power generation	1.50	2.22	0.77
Residential	4.20	4.51	4.39
Own consumption	6.11	6.18	6.10
INTERNATIONAL SALES	37.68	43.40	47.88
Rest of Europe	29.42	38.23	42.43
Importers in Italy	3.42	3.89	4.37
European markets	26.00	34.34	38.06
Iberian Peninsula	4.65	5.06	5.28
Germany/Austria	1.83	6.95	7.81
Benelux	5.29	5.06	7.03
Hungary			0.93
United Kingdom/Northern Europe	2.22	2.21	2.01
Turkey	6.53	8.03	6.55
France	4.95	6.38	7.42
Other	0.53	0.65	1.03
Extra European markets	8.26	5.17	5.45
WORLDWIDE GAS SALES	76.71	80.83	86.31

The LNG business

Eni LNG business can count currently on a portfolio of contracted long-term supplies mainly from Indonesia, Qatar, Nigeria, Oman and Algeria. In the plan period, Eni intends to develop its LNG business leveraging on the integration with the E&P segment and the valorization of the equity gas. Final markets of that gas include Europe, China, Japan, Pakistan and Taiwan.The business's profitability will be also driven by enhancing the commercial presence in premium markets and continuing integration with trading activities.

LNG sales	2018	2017	2016
	(BCM)		
G&P sales	10.3	8.3	8.1
Rest of Europe	4.7	5.2	5.2
Extra European markets	5.6	3.1	2.9

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 leveraging on the Company's large gas availability. In addition, with the aim of developing and retaining valuable customers in the residential space and small and middle business located in urban area, the Company has developed a commercial offer that provides the combined supply of gas and power to the retail market in Italy and in France.

In 2018, power sales (37.07 TWh) were directed to the free market (70%), the Italian Power Exchange (19%), industrial sites (10%) and others (1%). Compared to 2017, electricity sales in the free market were down by 0.62 TWh or by 2.3%, due to lower volumes sold to large customers, middle market and small and medium-sized enterprises, partially offset by higher volumes sold to the wholesalers segment.

Power availability	2018	2017	2016
	(TWh)		
Power generation sold	21.62	22.42	21.78
Trading of electricity(a)	15.45	12.91	15.27
	37.07	35.33	37.05
Power sales by market			
Free market(a)	25.91	26.53	27.49
Italian Exchange for electricity	7.17	5.21	5.64
Industrial plants	3.49	3.01	3.11
Other(a)	0.50	0.58	0.81
	37.07	35.33	37.05

(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 2018, power generation was 21.62 TWh, down by 0.80 TWh or by 3.6% from 2017. As of December 31, 2018, installed operational capacity was 4.7 GW, unchanged compared to December 31, 2017. Electricity trading (15.45 TWh) reported an increase of 19.7% thanks to the optimization of inflows and outflows of power.

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Site	Total installed capacity in 2018 (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.

Power generation		2018	2017	2016
Purchases				
Natural gas	(mmCM)	4,300	4,359	4,334
Other fuels	(ktoe)	356	392	360
- of which steam cracking		94	104	105
Production				
Electricity	(TWh)	21.62	22.42	21.78
Steam	(ktonnes)	7,919	7,551	7,974
Installed generation capacity	(GW)	4.7	4.7	4.7

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 (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.
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.

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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.

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

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 to produce a large slate of fuels and other refined products and in the marketing of fuels primarily in Italy and in selected European markets. In Italy, Eni is the largest refining and marketing operator in terms of capacity and market share. The Company operations are fully integrated through refining, supply, logistics and marketing in order to maximize cost efficiencies and operational effectiveness.

The Company also engages in the production of bio-fuels at the Venice refinery, where certain renewable feedstock are processed (palm oil).

The business results depends heavily on trends in refining margins, i.e. the spread between the cost of the oil feedstock and the price of the refined products obtained from the crude processing.

In 2018 refining margins in the Mediterranean area decreased by approximately 26% y-o-y to 3.7 $/BBL driven by the sharp increase of oil prices reported in the first ten months, not recovered in the sale prices of refining products due to competitive pressure in the markets. Management believes that refining margins will remain under pressure in the short-to-medium term due to continuing competition. In the medium-term, spreads between products and crude may find a support 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 2018 and its strategy are described in “Item 5 – 2016-2018 Group results of operations” and “Item 5 – Management’s expectations of operations”.

Supply

In 2018, a total of 22.62 mmtonnes of crude were purchased (compared with 24.28 mmtonnes in 2017), of which 4.14 mmtonnes by equity crude oil. The breakdown by geographic area was the following: approximately 36% of purchased crude came from the Middle East, 18% from Russia, 14% from Italy, 13% from Central Asia, 10% from North Africa, 3% from West Africa, 2% from North Sea and 4% from other areas.

Refining

In 2018, 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

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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 56% conversion index. In 2018, Eni's refineries throughputs in Italy and outside Italy were 23.23 mmtonnes. The refinery utilization rate, ratio between throughputs and refinery capacity, is 90,1%.

Refining system in 2018

	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	90	56	34	40	71	29
Italy								
Sannazzaro	100	200	93	74	34	14	51	29
Taranto	100	104	73	56		26	20	
Livorno	100	84	100	11				
Partially owned refineries		160	94	52	143	25	75	27
Italy								
Milazzo	50	100	99	60	45	25	32	
Germany								
Vohburg/Neustadt (Bayernoil)	20	41	77	36	49			
Schwedt	8.33	19	100	42	49		43	27
Total		548	91	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 74%. 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.

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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).

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 (2018) (ktonnes/y)	Capacity (at regime) (ktonnes/y)	Throughput (2018) (ktonnes/y)
Wholly-owned				
Venezia	100	360	560	253
Gela	100		750	
Total green refineries		360	1,310	253

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, replacing the old oil-based refinery that was shut down. The refinery, with a production capacity of 360 ktonnes/y, leverages on the EcofiningTM proprietary 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 in 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 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. Upgrading works have progressed in 2018. The project is expected to come on stream in 2019. The refinery will have a capacity of 750 ktonnes/y. The conversion will leverage on the application of the EcofiningTM 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.

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

Availability of refined products

	2018	2017	2016
	(mmtonnes)		
ITALY			
Refinery throughputs			
At wholly-owned refineries	16.78	16.03	17.37
Less input on account of third parties	(1.03)	(0.34)	(0.27)
At affiliated refineries	4.93	5.46	4.51
Refinery throughputs on own account	20.68	21.15	21.61
Consumption and losses	(1.38)	(1.36)	(1.53)
Products available for sale	19.30	19.79	20.08
Purchases of refined products and change in inventories	7.50	6.74	6.28
Products transferred to operations outside Italy	(0.54)	(0.46)	(0.39)
Consumption for power generation	(0.35)	(0.34)	(0.37)
Sales of products	25.91	25.73	25.60
Green refinery throughputs	0.25	0.24	0.21
OUTSIDE ITALY			
Refinery throughputs on own account	2.55	2.87	2.91
Consumption and losses	(0.20)	(0.22)	(0.22)
Products available for sale	2.35	2.65	2.69
Purchases of finished products and change in inventories	4.12	4.36	4.72
Products transferred from Italian operations	0.54	0.46	0.40
Sales of products	7.01	7.47	7.81
Refinery throughputs on own account	23.23	24.02	24.52
of which: refinery throughputs of equity crude on own account	4.14	3.51	3.43
Total sales of refined products	32.92	33.20	33.41
Crude oil sales	0.28	0.86	0.20
TOTAL SALES	33.20	34.06	33.61

In 2018, refining throughputs were 23.23 mmtonnes, down by 3.3% from 2017 due to the lower throughputs at the Taranto plant, reflecting higher crude oil volumes processed on behalf of third parties, at the Milazzo refinery due to maintenance standstills and at the Bayernoil refinery following an event occurred in September. These negatives were partially offset by the better performance at the Sannazzaro and Livorno refineries, with the latter affected in 2017 by a shutdown due to a force majeure event.

Outside Italy, Eni's refining throughputs were 2.55 mmtonnes, down by 320 ktonnes or 11.1% due to the above-mentioned event occurred at the Bayernoil refinery.

Total throughputs in wholly-owned refineries were 16.78 mmtonnes, up by 0.75 mmtonnes or 4.7% compared with 2017.

Approximately 18.3% of processed crude was equity, increased approximately 3.1 percentage points from 2017 (15.2%).

The volumes of biofuels produced from vegetable oil at the Venice green refinery increased by 4.2% from the corresponding period of 2017.

Logistics

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

It owns an integrated infrastructure consisting of 15 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 seven different joint ventures (Sigemi, Petroven, Seram, Disma, Seapad, Toscopetrol and Sarroch. 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 1.149 kilometers in operation.

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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.

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	2018	2017	2016
	(mmtonnes)		
Italy			
Retail	5.91	6.01	5.93
Wholesale	7.54	7.64	8.16
	13.45	13.65	14.09
Petrochemicals	0.96	0.86	1.02
Other sales	11.5	11.22	10.49
Total	25.91	25.73	25.60
Outside Italy			
Retail	2.48	2.53	2.66
Wholesale	3.29	3.48	3.61
	5.77	6.01	6.27
Other sales	1.24	1.46	1.54
Total	7.01	7.47	7.81
TOTAL SALES	32.92	33.20	33.41

In 2018, sales volumes of refined products (32.92 mmtonnes) were down by 0.28 mmtonnes or by 0.8% from 2017, mainly due to the decrease of retail and wholesale sales in Italy and lower volumes marketed in the wholesalers segment in the rest of Europe.

Retail sales in Italy

In 2018, retail sales in Italy were 5.91 mmtonnes, with a slight decrease compared to 2017 (about 100 ktonnes from 2017 or 1.7%). Average gasoline and gasoil throughput (1,589 kliters) were substantially in line with 2017. Eni's retail market share of 2018 was 24%, down by 0.3 percentage points from 2017 (24.3%).

As of December 31, 2018, Eni's retail network in Italy consisted of 4,223 service stations, lower by 87 units from December 31, 2017 (4,310 service stations), resulting from the negative balance of acquisitions/ releases of lease concessions (74 units), closure of low throughput stations (10 units) and the reduction in motorway concessions netted by the new opening (3 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 2018, retail sales of refined products in the rest of Europe (2.48 mmtonnes), recorded a reduction from 2017 (down by 2%). This result reflected mainly lower volumes traded in Germany due to the event occurred at Bayernoil refinery and France.

At December 31, 2018, Eni's retail network in the rest of Europe consisted of 1,225 units, decreasing by 9 units from December 31, 2017, mainly in Germany. Average throughput (2,391 kliters) decreased by 49 kliters compared to 2017 (2,440 kliters).

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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 (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 2018, sales volumes on wholesale markets in Italy (7.54 mmtonnes) were in line from the full year of 2017, mainly due to lower volumes marketed of gasoil offset by higher sales of other products.

Wholesale sales in the Rest of Europe were 2.82 mmtonnes, down by 6.9% from 2017 due to lower sold volumes in Germany and France, partly offset by higher volumes in Spain.

Supplies of feedstock to the petrochemical industry (0.96 mmtonnes) increased by 11.6%. Other sales in Italy and outside Italy (12.74 mmtonnes) slightly increased by 0.06 mmtonnes, mainly due to higher volumes sold 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 2018, Eni share of LPG market in Italy was 17.8%.

Outside Italy, the main market of Eni is Ecuador, with a market share of 37.3%.

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 2018, Eni’s share of lubricants market in Italy was 19.06%, in Europe 3% and on a worldwide base 1%. 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 0.9 mmtonnes/y of oxygenates, mainly ethers (approximately 3% of world demand, used as a gasoline octane booster) and methanol (mainly for petrochemical use). About 79% 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 21% 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.

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The business results of operations in 2018 and its strategy are described in "Item 5 – 2016-2018 Group results of operations" and "Item 5 – Management's expectations of operations".
In 2018 sales of chemical products amounted to 4,938 ktonnes, increased from 2017 (up by 292 ktonnes, or 6.3%). The main increases were registered in olefins (up by 14.8%) and derivatives (up by 20.4%), partly offset by lower sales volumes of polyethylene (down by 6.3%) and elastomers (down by 3.2%).
Average unit sales prices of the intermediates business increased by 7.1% from 2017, with olefins and aromatics up by 10.9% and 4,2%, respectively. Despite, the polymers reported a decrease of 2.4% from 2017.
Petrochemical production of 9,483 ktonnes increased by 528 ktonnes (up by 5.9%) mainly due to higher production of intermediates business (up by 8.1%), in particular derivatives up by 17.6%; the polymers productions were substantially in line despite the improvement of styrenics (+8.3%).
The main increases in production were registered at the Porto Marghera site (up by 22.9%), due to a recovery of production capacity for a shutdown in 2017, as well as Szàshalombatta, Mantova and Priolo sites. Decreasing productions at the Ferrara, Brindisi and Oberhausen sites due to unplanned shutdowns of the plants in 2018.
Nominal capacity of plants is in line from the previous year. The average plant utilization rate calculated on nominal capacity was 76.2% increased from 2017 (72.8%).
The table below sets forth Eni's main chemical products availability for the periods indicated.

	Year ended December 31,		
	2018	2017	2016
	(ktonnes)		
Intermediates	7,130	6,595	6,580
Polymers	2,353	2,360	2,229
Total production	9,483	8,955	8,809
Consumption and losses	(5,085)	(4,566)	(4,917)
Purchases and change in inventories	540	257	853
	4,938	4,646	4,745

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

	Year ended December 31,		
	2018	2017	2016
	(€ million)		
Intermediates	2,401	1,988	1,688
Polymers	2,589	2,730	2,380
Other revenues	130	133	128
Total revenues	5,120	4,851	4,196

Intermediates
Intermediates revenues (€2,401 million) increased by €413 million from 2017 (up by 20.8%) reflecting the higher commodity prices scenario that influences average intermediates prices of the main product of the business unit. Sales increased by 12.3%, in particular for ethylene business (up by 30.3%) and derivatives (up by 20.4%) driven by higher availability of product following the shutdowns in 2017.
Average unit prices increased by 7.1%, in particular olefins (up by 10.9%) and aromatics (up by 4.1%); decreasing of derivatives (down by 9.3%).
Intermediates production (7,130 ktonnes) registered an increase of 8.1% from the last year. Increasing of derivatives (up by 17.6%), aromatics (up by 8.3%) and olefins (up by 7%).

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Polymers

Polymers revenues (€2,589 million) decreased by €141 million or 5.2% from 2017 due to lower sales volumes (down by 2.5%), as well as to the decrease of the average unit prices (down by 2.4%).

The styrenics business benefitted from the high sold volumes (up by 5.8%) for higher product availability; slightly decrease of sold prices (down by 1.4%).

Polyethylene volumes decreased (down by 6.4%) due to oversupply and mounting competitive pressure from cheaper products streams from the Middle-East and the USA; decreasing of average prices (down by 3.9%).

Polymers productions are in line from 2017 (2,353 ktonnes) despite the lower productions of polyethylene (down by 7.3%) and elastomers (down by 2.7%). The styrenics business reported higher production of styrene (up by 12.1%) and HIPS (up by 11.7%).

Versalis also engages in the production of chemicals from renewables sources through a 50%-owned joint venture with Novamont for the production of chemicals from crop and the acquisition in 2018 of the segment of green chemicals of the Mossi & Ghisolfi Group. In particular, the new assets will allow the valorization of biomass and the re-launch of the international licensing of a proprietary technology to produce second generation bio-ethanol, to meet the growing demand and sustainability criteria required for bio-fuels.

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.

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Research and development

Research and development is a key element in Eni's transformation into an integrated energy company in a low-carbon future. The availability and development of cutting-edge technological skills at the service of innovation and sustainability and the continuous commitment to multiply the areas of application of the energy solutions identified are the common denominator of our activities.

Research projects cover every aspect of our value chain, with the aim of reducing risks and increasing efficiency, consolidating technological leadership and, in general, achieving greater quality, efficiency and sustainability in products, plants and processes.

Research and Development becomes, therefore, the lever to create value, with the aim of minimizing the time to market that from research leads to the development of technologies and their implementation on an industrial scale.

In 2018, Eni filed 43 patent applications (27 in 2017).

In 2018, Eni's overall expenditure in R&D amounted to €197 million which were almost entirely expensed as incurred (€185 million in 2017 and €161 million in 2016).

Exploration & Production

Proprietary software for seismic signal processing, petroleum system modeling and flow assurance that confirms and strengthens Eni's position at the top of the industry, both in terms of operating results and with significant savings on the cost of licenses and code maintenance.

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: 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.

Eni Subsea Hub Technology Solutions: 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 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 and Petrochemicals

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.

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.

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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 CO2 emissions.

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.

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, with a pilot plant in Gela (Sicily) and a demo plant of 1MW thermal power.

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.

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 CO2 (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 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. A pilot has been developed in Gela and it started the operations at the end of 2018.

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Energy Transition

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) H2S management,

c) CO2 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 H2S and CO2 capture, innovative highly effective solvents for the separation of H2S and CO2 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.

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

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 2018, 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 185 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 2018, the UN Climate Change Conference (COP 24) had taken place in Katowice (Poland). The COP 24 was the next step for governments to implement the Paris Agreement "rulebook" 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 final Decision of the COP24 defined the guidelines for most of the major mechanisms introduced by the Paris Agreement, such as the financial support for developing countries, the preparation and communication of the Parties emission reduction commitments, the periodic review of the results and the transparency of the information. However, the COP24 did not make any progress on the rules for the carbon offsets development and emission trading between Parties and privates (article 6 of the Paris Agreement). On this topic, the negotiations could not go over the impasse due to a divergence between the Parties on a few crucial points.

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 the revision of the 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.

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Negotiations have now been concluded on all aspects of the new Clean Energy Package and all of the new rules will be formally adopted in the 2019. Finalising these changes will mark a significant step towards the creation of the Energy Union and delivering on the EU's Paris Agreement commitments. The new legislative package strengthens two existing targets for the EU by 2030: a binding renewable energy target of at least 32% and an energy efficiency target of at least 32.5% – with a possible upward revision in 2023. For the electricity market, it confirms the 2030 interconnection target of 15%, following on from the 10% target for 2020. These policies will lead to steeper emission reductions for the whole EU than anticipated – some 45% by 2030 relative to 1990 (compared to the existing target of a 40% reduction). The revised Renewable Energy Directive sets also the target for renewable energy in the transport sector. In particular, Member States must require fuel suppliers to supply a minimum of 14% of the energy consumed in road and rail transport by 2030 as renewable energy. Within the target, the advanced biofuels must be supplied at a minimum of 0.2% of transport energy in 2022, 1% in 2025 and increasing to at least 3.5% by 2030. On the other hand, biofuels produced from food and feed crops will be frozen at 2020 consumption levels plus an additional 1% with a maximum cap of 7% of road and rail transport fuel in each Member State. Lastly, biofuels produced from used cooking oil and animal fats will be capped at 1.7% in 2030, even if Member States may, where justified, modify that limit, taking into account the availability of feedstock. In terms of environmental sustainability, the European Commission set out limits and sustainable criteria on high Indirect Land Use Change-risk feedstocks, such as palm oil. These feedstocks will be capped at 2019 levels until 2023. After that, they will be progressively phased-out up to zero percent by 2030.

The Clean Energy Package also sets up a robust governance system for the Energy Union and each Member State is now required to draft integrated national energy and climate plans for 2021 to 2030 outlining how they will achieve their respective targets. A further part of the package seeks to establish a modern design for the EU electricity market, adapted to the new realities of the more flexible market, better placed to integrate a greater share of renewables.

The Clean Energy Package targets also played an important part in the Commission's preparation for its long-term vision for a climate neutral Europe by 2050, published on 28 November 2018, before the COP24. The 2050 strategy shows how Europe can lead the way to climate neutrality by investing into realistic technological solutions, empowering citizens and aligning action in key areas such as industrial policy, finance or research – while ensuring social fairness for a just transition. The 2050 strategy will be firstly debated at the European Council on May 9, 2019 in Sibiu and then adopted by the European Council in the second half of 2020.

Under the electricity market reform, a Directive and a Regulation, the European Commission introduced a new limit for power plants eligible to receive subsidies as capacity mechanisms. Subsidies to generation capacity emitting 550gr CO_2/kWh or more will be phased out, as of 2020 for new infrastructure and as of 2025 for existing plants. The Commission's proposal has been approved and emerges as one the main points of the EU climate legislation. The 550gr criterion, used in the European Investment Bank's policy, is technology neutral and in practice preclude from the subsidies the coal power plants and some inefficient gas plants.

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 (EU 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%. The new list of carbon leakage sectors has also been published and includes all the Eni's activity sectors excluding the extraction and production of natural gas. The carbon leakage sectors will receive 100% of the free allowances calculated with the sectorial benchmark, for all the IV phase (2021 – 2030). Currently around 46% of Eni's direct GHG emissions are included within the Carbon Pricing Scheme by its participation in the EU ETS.

In May 2018, the European institutions adopted the Effort Sharing Regulation (ESR) to ensure further emission reductions in sectors falling outside the scope of the EU emissions trading system (ETS) for the period 2021 – 2030. The ESR maintains existing flexibilities (e.g. banking, borrowing and buying

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and selling between Member States) and provides two new flexibilities, allowing the use of some EU ETS emissions allowances and credits from land use sector to achieve the final target. 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.

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 June 30, 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 March 31, 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 July 31, 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 January 1, 2018 to December 31, 2020 for each producer or importer which has lawfully placed on the market hydrofluorocarbons from January 1, 2015 UE of October 24, 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

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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 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.

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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.

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.

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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 2018

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 2018, 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 294, of which:

- 88 certifications according to the ISO 14001 standard;
- 10 registrations according to the EMAS regulation (EMAS is the Environmental Management and Audit Scheme recognized by the European Union);
- 22 certifications according to the ISO 50001 standard (certification for an energy management system);
- 95 according to the OHSAS 18001 standard (Occupational Health and Safety management Systems – requirements) and 6 according to the new ISO 45001 standard;
- 40 according to the ISO 9001 standard (certification of the quality management system).

In 2018 the percentage of Eni industrial installations and operating units with a significant HSE risk covered by certification is 94% for the OHSAS 18001/ISO 45001 standard and 93% for the ISO 14001 standard.

In 2018, total HSE expenses (including cross-cutting issues such as HSE management systems implementation and certification, etc.) amounted to €1,254 million (+14% vs 2017).

Environment. In 2018, Eni incurred total expenditures of €914 million for the protection of the environment (with an increase of 21% with respect to 2017). Environmental expenditures are mainly related to remediation and reclamation activities (€374 million), waste management (€224 million), water management (€131 million), air protection (€66 million) and spill prevention (€41 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 2018, the new legislation didn't impact significantly procedures already in place for safety in the workplace.
The dissemination of safety culture is a value for Eni. In 2018, in order to increase safety's culture in the workforce, awareness-raising initiatives continued and a new one was launched.
Below the main initiatives 2018 to strengthen the safety culture:

- Safety starts @ home: realization of videos, based on safety golden rules, on safe behavior even at home

- Inside Lesson Learned Project: dissemination and sharing of the most significant lessons learned through video clips in Italy and abroad;

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- Io vivo sicuro: theatrical events or roundtables to raise awareness among top management, contractors and external guests

- Process safety workshop and newsletter: two workshops were organized on the following topics “Fire prevention” and “Pressure equipment”, aimed at professionals in the safety field, and Eni personnel engaged in technical, technological and plant manager services. Quarterly newsletter on process safety were disseminated at company level.

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.
Despite all the initiatives and activities carried out in 2018, the Total Recordable Injury Rate for the workforce worsened by 6% compared to 2017 (0.35 vs 0.33).
Regarding emergency preparedness to oil spill, 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 set-up after the Macondo accident.
The OSR-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 Eni participates at two Global Initiatives jointly led by the IMO and IPIECA: OSPRI (Black Sea, Caspian Sea and Central Eurasia) and WACAF (West, Central and Southern Africa).
Costs incurred in 2018 to support the safety levels of operations and to comply with applicable rules and regulations were €260 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;

- 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.

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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.

Information about Eni's strategy and targets in a low-carbon scenario in accordance to standards set by the Task Force on climate-related Financial Disclosures (TCFD) of the Financial Stability Board and other non-financial information about sustainability is provided in the “Non-financial Information report” which is part of Eni’s 2018 Annual Report published in accordance with Italian law and practice. These reports are not incorporated by reference in this Form 20-F.

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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.

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 production taxes or royalties, which may be in cash or in-kind. Concession contracts currently applied mainly in Western countries regulating relationships between States and oil companies with regards to hydrocarbon exploration and production activity. 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. Contractual clauses governing mineral concessions, licenses and exploration permits regulate the access of Eni to hydrocarbon reserves. The company holding the mining concession has an exclusive right on exploration, development and production activities, sustaining all the operational risks and costs related to the exploration and development activities, and it is entitled to the productions realized. As a compensation for mineral concessions, pays royalties on production (which may be in cash or in-kind) and taxes on oil revenues to the state in accordance with local tax legislation.

Proved reserves to which Eni is entitled 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.

Eni operates under Production Sharing Agreement (PSA) in several foreign jurisdictions mainly in African, Middle Eastern and Far Eastern countries. 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 (technologies) 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.

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 Company's share of production volumes and reserves representing the Profit Oil includes the share of hydrocarbons which corresponds to the taxes to be paid, according to the contractual agreement, by the national government on behalf of the Company. Therefore, the Company recognizes at the same time an increase in the taxable profit, through the increase in revenues, and a tax expense. 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 to PSA applies to Service 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.

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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.

These provisions are to be coordinated with a new law effective as of February 12, 2019, which requires certain Italian administrative bodies to adopt within eighteen months a plan indented to identify areas that are suitable for carrying out exploration, development and production of hydrocarbons in the national territory, including the territorial seawaters. Until approval of such a plan, it is established a moratorium on exploration activities, including the award of new exploration leases. Following the plan approval, exploration permits resume their efficacy in areas that have been identified as suitable; on the contrary, in unsuitable areas, exploration permits are repealed. As far as development and production concessions are concerned, pending the national plan approval ongoing concessions retain their efficacy and administrative procedures underway to grant extension to expired concession remain unaffected; instead no applications to obtain new concession can be filed. Once the above mentioned national plan is adopted, development and production concessions that fall in suitable areas can be granted further extensions and applications for new concessions can be filed; on the contrary development and production concessions current at the approval of the national plan that fall in unsuitable areas are repealed at their expiration and no further extensions can be granted, nor new concession applications can be filed. In case Italian administrative bodies fail to adopt the national plan for suitable areas within two years from the law enactment, the general moratorium on exploration activities is revoked and application for new concession permits can be filed. According to the statute, areas that suitable to the activities of exploring and developing hydrocarbons must conform to a number of criteria including morphological characteristics and social, urbanistic and industrial constraints, with particular bias for the hydrogeological balance, current territorial planning and with regard to marine areas for externalities on the ecosystem, reviews of marine routes, fishing and any possible impacts on the coastline.

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

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Decree, was converted to Law No. 20 on March 24, 2012. This law aimed at:

- enhancing competitiveness in gas tariffs to residential customers. The Italian authority in charge with setting pricing mechanisms for gas supplies to certain categories of end-users (ARERA) started from the second quarter of 2012 a process to revise the indexation mechanism of the raw material component by gradually increasing the weight of spot prices in the indexation of the supply costs of gas thus replacing the oil-linked indexation (see below); 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 are due to establish yearly 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.

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.

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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 retains a power of surveillance on this matter as per 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 fully enacted by ARERA targeting 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 (principally households, 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 at the TTF (Title Transfer Facility) hub in Northern Europe, replacing the then current 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 due to possible indexation mismatches by introducing a pricing component intended to compensate wholesalers for losses that they would incur on those risks. 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 would 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. Those provisions explicated their effects in 2014 – 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. This new tariff indexation aiming at safeguarding the purchase-power of households was initially intended to remain effective till July 1, 2019 (as provided by Law 124/17). However, this deadline has been prorogated by one year (as per Law Decree 91/2018). From that point onwards, households in Italy will no longer have access to regulated tariffs for gas supplies. Consumers will have to choose among the different pricing proposals made by gas selling companies. The ARERA has established that gas selling companies comply with certain requirements about the offerings to customers which include at least two pricing indexations (fixed and variable), both complemented with contractual conditions regulated by the ARERA. Management believes that this development will increase competition in the Italian retail market for selling gas.

Other regulatory developments in the gas and electric sector in Italy

The Italian ARERA is currently reviewing gas transport tariffs along the Italian backbones to define tariff criteria intended to allow gas transport operators recover their operating costs for the next three-year time frame. This could potentially open opportunities to gas shippers, like Eni, due to the proposed elimination of long-term, ship-or-pay contracts at the points of access to the Italian national transport

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system. It is worth mentioning that an administrative measure introduced by ARERA effective from thermal year 2017 – 2018 helped gas shippers to recover part of the sunk costs associated with transport capacities at the points of access to the Italian network, which were booked by the shippers through multi-year arrangements. According to this measure, any unfilled transport capacity at the expiration of those multi-year arrangements may be recovered in the subsequent three-year time frame, with a net benefit to logistic costs.

Refining and marketing of petroleum products

Refining. The current regulations on refining activity in Italy provides that Italian administrative bodies authorize plans filed by refining operators intended to set up new processing and storage plants and to upgrade capacity, while all other changes that do not affect capacity can be freely implemented. This regime was streamlined by Law Decree No. 5/2012 that defined mineral oil processing and storage plants as “strategic installations” that need authorization from the State, in agreement with the local administrations. The Decree introduced a unitized process of authorization that must be finalized within 180 days, subject to compliance with applicable environmental regulations. the company has not experienced any material delays in obtaining relevant concessions for the upgrading of the Sannazzaro underway.

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.. 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. Subsequently, various regulations have been enacted in Italy with the aim of improving network efficiency, modernizing service stations and opening up the market. Currently, all service stations are provided with self-service equipment and the sale of non-oil products has been broadly introduced by local administrative bodies. 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 – has introduced minimum requirements for the construction of infrastructure for the development of alternative fuels to mitigate the environmental impacts of the transport sector. The legislation established, furthermore, an adequate number of charging stations accessible to the public to be created throughout the country by 2020.

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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.

In order to support the achievement of the renewables target in the transport sector established by the EU and national laws, the Ministerial Decree of 2 March 2018, provides the legislative framework to incentivize the production of both biomethane and other advanced biofuels to be used in the transport sector.

The Decree provides incentives for plants starting operations between 2018 and 2022 and to plants that are converted to biomethane production.

The incentive consists in an allocation of a Certificate (CIC) for every 10 Gcal of biomethane produced. The certificate has a market value since fossil fuel marketers have to sell a minimum percentage of biofuels annually, for which they receive the same Certificates.

In order to access to incentives, producers must comply with legal and technical regulations governing the quality and certification of the produced biomethane, verified by the competent Authority (Gestore dei Servizi Energetici, GSE). These measure aims to favor advanced biofuels production through the valorization of waste, notably of agricultural and farm/zoo technical waste.

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, 2018, Eni owned 5.1 mmtonnes of oil products inventories, of which 3.4 mmtonnes as "compulsory stocks", 1.5 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 (34%), light and medium distillates (36%), refinery feedstock (21%), fuel oil (4%) and other products (5%) were located throughout the Italian territory both in refineries (84%) and in storage sites (16%).

Competition

Like all Italian companies, Eni is subject to Italian and EU competition rules. EU competition rules are set forth in Articles 101 and 102 of the Lisbon Treaty on the Functioning of the European Union entered into force on December 1, 2009 ("Article 101" and "Article 102", respectively being the result of the new denomination of former Articles 81 and 82 of the Treaty of Rome as amended by the Treaty of Amsterdam dated October 2, 1997 and entered into force on May 1, 1999) and EU Merger Control Regulation No. 139 of 2004 (EU Regulation 139). Article 101 prohibits collusion among competitors that

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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 do 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. The Company enters into operating lease contracts with third parties to hire plant and equipment such as floating production and storage offloading vessels (FPSO), drilling rigs, time charter, service stations and other equipment. 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.

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Organizational structure

Eni SpA is the parent company of the Eni Group. As of December 31, 2018, there were 213 subsidiaries and 103 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, 2018 is provided in the notes to the Consolidated Financial Statements.

Item 4A. UNRESOLVED STAFF COMMENTS

None.

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Item 5. OPERATING AND FINANCIAL REVIEW AND PROSPECTS

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

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

Executive summary

Key consolidated financial data

		2018	2017	2016
		(€ million)		
Net sales from operations from continuing operations		75,822	66,919	55,762
Operating profit (loss) from continuing operations		9,983	8,012	2,157
Net profit (loss) attributable to Eni from continuing operations		4,126	3,374	(1,051)
Net profit (loss) attributable to Eni from discontinued operations				(413)
Net profit (loss) attributable to Eni		4,126	3,374	(1,464)
Net cash provided by operating activities – continuing operations		13,647	10,117	7,673
Capital expenditures – continuing operations		9,119	8,681	9,180
Disposal of assets, consolidated subsidiaries and businesses		1,242	5,455	1,054
Shareholders' equity including non-controlling interest at year end		51,073	48,079	53,086
Net borrowings at year end		8,289	10,916	14,776
Net profit (loss) attributable to Eni basic and diluted from continuing operations	(€ per share)	1.15	0.94	(0.29)
Dividend per share	(€ per share)	0.83	0.80	0.80
Ratio of net borrowings to total shareholders' equity including non-controlling interest (leverage)(1)		0.16	0.23	0.28

(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

In the full year 2018, net profit attributable to Eni's shareholders was €4,126 million, up by 22.3% vs. the prior-year (€3,374 million); operating profit of €9,983 million represented a 24.6% increase over 2017 (up by approximately €2 billion).

Eni's results were supported by a better trading environment with average Brent prices increasing by 31% from 2017 to 71 $/barrel in 2018, in a highly volatile scenario. In the first ten months of the year, oil prices built on gains peaking at 85 $/barrel in October, the highest level in the last four years, due to a global economic recovery and a balanced demand/supply backdrop. Starting from November, alongside a sharp correction in the global financial markets, oil prices entered a downturn losing about 40% from the peak, falling to approximately 50 $/barrel at the end of the year, due to signs of weakening global growth, oversupplies, uncertainties tied to the commercial dispute between the USA and China and the Brexit, as well as geopolitical factors. In December, OPEC and Russia announced a production cut of 1.2 million barrel/d effective from 2019, which helped crude oil prices rebound to the sixty-dollars level in the first months of 2019.

In this scenario, Eni's E&P segment reported an increase in operating profit of €2.56 billion, leveraging on better prices and production increases, with the latter boosted by a shift in the production mix towards barrels with higher profitability. Hydrocarbons production rose to 1.73 mmBOE/d, with a 1.3% annual grow at constant prices (1% on reported basis), driven by Eni's successful strategy of reducing the time-to-market of its reserves as witnessed by five new field start-ups in the year and fast ramp-up at core projects like the Zohr gas field in Egypt. The reserve replacement ratio was 124% on all-sources basis;

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when stripping out asset purchases and divestments the ratio was still 100%. The de-booking of proved reserves made at a project in Venezuela negatively affected the reserve replacement ratio by fifteen percentage points and was driven by a deteriorated operating environment.

The all-sources reserve replacement ratio improved significantly from the year-ago ratio of 27% due to the fact that in 2017 the Company divested significant interests in the properties of Zohr and Area 4 in Mozambique.

The G&P segment improved its operating profit by approximately €0.6 billion, driven by the overall restructuring of all the business lines. The Company was able to monetize the flexibilities associated with the portfolio of long-term gas contracts, as in the case of the option to lift additional volumes of gas beyond the minimum contractual take in case of favourable market trends like the ones that occurred in the first nine months of the year with a tighter gas market. Also, optimization in the power business and in logistics, as well as growth in the LNG business leveraging its integration with the E&P segment helped the segment's results.

The downstream oil and chemical businesses were negatively affected by a challenging trading environment (approximately down by €1.4 billion) because of rapidly-escalating oil-based feedstock costs in the first ten months of the year, which were not fully recovered in the final prices of products due to competitive pressure from more efficient producers and a slowdown in markets for oil and chemicals commodities in the final part of the year. Those market developments caused a squeeze in commodity margins (the SERM benchmark refining margin was down by 26% to 3.7 $/barrel; the cracker margin down by 11% and the polyethylene margin was down by 69%), the effects of which were partly offset by improved margins on retail sales of fuels and efficiency gains.

Adjusted results

Adjusted operating profit and adjusted net profit are determined by excluding from the reported results inventory holding gains or losses and non-core 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 underlying operations by excluding the effects of certain disposals and 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 underlying trends in 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 judgment, book value of assets, capital structure and the method by which assets were acquired, among other factors.

In 2018, non-core items, including the gain of the initial recognition of Eni's interest in Vår Energi resulting from the business combination between the fully-owned subsidiary Eni Norge and Point Resources (as difference between the fair value of the investment and the book value of disposed net asset), the gain on the divestment of a 10% interest in the Zohr gas field, impairment losses and other non-core charges were a net negative of €388 million in net profit and of €1,161 million in operating profit. Furthermore, an inventory holding loss of €69 million (€96 million pre-tax) was recorded due to declining crude oil and products prices at end of the year reflected in the alignment of inventories at their net realizable values.

The Group underlying performance – i.e net of the effect of non-core gains and losses and the inventory holding loss – resulted in adjusted net profit for the year of €4,583 million compared to €2,379 million in 2017, and in adjusted operating profit of €11,240 million compared to €5,803 million in 2017, almost doubling y-o-y, up by €5.44 billion. The increase in adjusted operating profit was driven by higher results in the E&P segment which doubled its operating profit at €10,850 million, up by €5.68 billion, and by a recover in profitability at the G&P segment with a €0.33 billion gain. Price and margin effects accounted for €4 billion, while improvements in the underlying performance driven by production growth and a better volume mix in the E&P segment accounted for €1.4 billion.

The table below sets forth details of the identified non-core gains and losses included in the net results during the period presented.

Eni Group	Year ended December 31, 2018	2017	2016
	(€ million)		
(Profit) loss on inventory	96	(219)	(175)
Environmental provisions	325	208	193
Impairment losses (impairments reversals), net	866	(221)	(459)
Impairment of exploration projects			7
Net gains on disposal of assets	(452)	(3,283)	(10)
Risk provisions	380	448	151
Provision for redundancy incentives	155	49	47
Reinstatement of Eni Norge amortization charges(1)	(375)		
Fair value gains/losses on commodity derivatives	(133)	146	(427)
Reclassification of currency derivatives and exchange effects to management measure of business performance	107	(248)	(19)
Estimate revision of revenues accrued in the gas retail business		64	161
Valuation allowance of doubtful accounts(2)		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	288	231	279
Total net non-core items in operating profit	1,257	(2,209)	158
Finance expenses	(85)	502	116
of which: reclassification of currency derivatives and exchange effects to management measure of business performance	(107)	248	19
Capital gains on disposal of investments	(909)	(163)	(57)
Write downs of investments and financing receivables	67	537	483
Write down of deferred tax assets/utilization of deferred tax liabilities	99		170
Tax effects relating to the US tax reform		115	
Tax effects on the above listed items and other items	55	160	(214)
Tax effects on (profit) loss on inventory	(27)	63	55
Net non-core items in net profit	457	(995)	711
Net (charges) gains attributable to non-controlling interest			
Net non-core items attributable to Eni	457	(995)	711

(1)
Management has evaluated to reinstate correlation between hydrocarbon production and reserve depletion by accruing the underlying UOP-based amortization charges of Eni Norge subsidiary classified in accordance to IFRS 5 due to the business combination with Point Resources. In the GAAP results, assets or disposal group held for sale are not to be depreciated or amortized.

(2)
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.

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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,		
	2018	2017	2016
	(€ million)		
GAAP measure of operating profit	9,983	8,012	2,157
Inventory holding (gains) and losses	96	(219)	(175)
Identified net (gains) losses	1,161	(1,990)	333
Total net non-core items in operating profit	1,257	(2,209)	158
Non-GAAP measure of operating profit	11,240	5,803	2,315
GAAP measure of net profit	4,126	3,374	(1,051)
Inventory holding (gains) and losses, post tax	69	(156)	(120)
Identified net (gains) losses, post tax	388	(839)	831
Total net non-core items in net profit	457	(995)	711
Non-GAAP measure of net profit	4,583	2,379	(340)

Cash flow from operating activities amounted to €13,647 million for the full year of 2018 and was up by 35% y-o-y, driven by an improved underlying performance and scenario effects. Cash flow from operating activities was affected by a lower level of receivables due beyond the end of the reporting period being sold to financing institutions, compared to 2017 (approximately €280 million). Other positive cash flows were associated with positive changes in receivables and payables associated with investing activities (mainly including the cash-in of the deferred price of the Zohr disposals made in 2017), which amounted to €0.9 billion. Asset disposals amounted to €1.24 billion. Capital expenditure for the year, including investments, was €9.36 billion. That amount included the following items: entry bonuses paid in connection with the acquisition of interests in two producing Concession Agreements and a third under development in the UAE (€869 million); non-strategic acquisitions in the gas mid-downstream business (approximately €100 million); the expenditures pertaining to a 10% divested interest in the Zohr project (€170 million) incurred from January 1, 2018 to the closing of the transaction (end of June 2018), which were reimbursed to Eni by the buyer.

After having funded capital expenditures and the dividend of €2.95 billion, the positive cash inflows of 2018 resulted in a significant surplus, which increased the Group’ s cash and cash equivalents on hand.

At December 31, 2018, the Group’s net debt decreased by €2,627 million to €8,289 million. The Group ratio of finance debt to total equity at year-end 2018 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 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 2018 decreased to 0.16 down from 0.23 at the end of 2017.

In 2019, we are projecting a capital expenditure budget of approximately €8 billion of which 80% relating to the E&P segment. That amount does not include the planned expenditures to acquire certain equity investments, particularly the acquisition of a 20% interest in the Ruwais refining complex in UAE with an expected expenditure of approximately €3 billion, which completion is forecast to occur by end of 2019.

We expect a production growth rate of approximately 2.5% compared to 2018 assuming constant crude oil prices and excluding portfolio transactions. Finally, we are projecting a cash dividend for the full year 2019 of €0.86 per share. See “Management expectations of operations”.

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Trading environment

	2018	2017	2016
Average price of Brent dated crude oil in U.S. dollars(1)	71.04	54.27	43.69
Average price of Brent dated crude oil in euro(2)	60.15	48.03	39.47
Average EUR/USD exchange rate(3)	1.181	1.130	1.107
Standard Eni Refining Margin (SERM)(4)	3.7	5.0	4.2
Euribor – three month euro rate %(3)	(0.32)	(0.33)	(0.26)

(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 is, 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 the first ten months of the year, oil prices built on gains peaking at 85 $/barrel in October, the highest level in the last four years, due to global economic growth and a balanced demand/supply backdrop. Starting from November, alongside a sharp correction in the global financial markets, oil prices entered a downturn losing about 40% from the peak, falling to approximately 50 $/barrel at the end of the year, due to signs of weakening global growth, oversupplies, uncertainties tied to the commercial dispute between the USA and China and Brexit, as well as geopolitical factors. In December, OPEC and Russia announced a production cut of 1.2 million barrel/d effective from 2019, which helped crude oil prices rebound to the sixty-dollars level in the first months of 2019.

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, decreased from a year ago (down by 26%) to 3.7 $/BBL driven by the sharp increase of oil prices reported in the first ten months, not recovered in the sale prices of refining products due to competitive pressure in the markets. Assuming the budget scenario of exchange rates and oil spreads, the breakeven SERM of Eni refineries is in line with our earlier guidance.

The exchange rate of euro against the dollar for 2018 was 1.181, with an appreciation of 4.5% compared to the average exchange rate recorded in 2017.

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 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

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environmental liabilities. Although the Company uses its best estimates and judgments, actual results could differ from the estimates and assumptions used. A review of significant accounting estimates and judgemental areas is provided in "Item 18 – Note 1 to Consolidated Financial Statements".

2016 – 2018 Group results of operations

Overview of the profit and loss account for three years ended December 31, 2016, 2017 and 2018

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,		
	2018	2017	2016
	(€ million)		
Net sales from operations	75,822	66,919	55,762
Other income and revenues(1)	1,116	4,058	931
Total revenues	76,938	70,977	56,693
Operating expenses	(59,130)	(55,412)	(47,118)
Other operating (expense) income	129	(32)	16
Depreciation, depletion and amortization	(6,988)	(7,483)	(7,559)
Impairment reversal (impairment losses), net	(866)	225	475
Write-off	(100)	(263)	(350)
OPERATING PROFIT (LOSS)	9,983	8,012	2,157
Finance income (expense)	(971)	(1,236)	(885)
Income (expense) from investments	1,095	68	(380)
PROFIT (LOSS) BEFORE INCOME TAXES	10,107	6,844	892
Income taxes	(5,970)	(3,467)	(1,936)
Net profit (loss) – continuing operations	4,137	3,377	(1,044)
Net profit (loss) – discontinued operations			(413)
Net profit (loss)	4,137	3,377	(1,457)
Attributable to:			
Eni's shareholders:	4,126	3,374	(1,464)
- continuing operations	4,126	3,374	(1,051)
- discontinued operations			(413)
Non-controlling interest:	11	3	7
- continuing operations	11	3	7
- discontinued operations			

(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,		
	2018	2017	2016

	(%)		
Operating expenses	78.0	82.8	84.5
Depreciation, depletion, amortization, impairment reversal (impairment losses) net, write-off	10.5	11.2	13.3
OPERATING PROFIT	13.2	12.0	3.9

2018 compared to 2017. In the full year 2018, net profit attributable to Eni's shareholders was €4,126 million, up by 22.3% vs. the previous year result (€3,374 million); operating profit of €9,983 million

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represented a 24.6% increase over 2017 (up by approximately €2 billion). Eni's results benefitted from a better trading environment with average Brent prices increasing by 31% from 2017 to 71 $/barrel, in a highly volatile scenario. For further details see management discussion in the paragraph "Executive summary".

2017 compared to 2016. 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.

Analysis of the line items of the profit and loss account

a) Total revenues

Eni's revenues were €76,938 million, €70,977 million and €56,693 million for the years ended December 31, 2018, 2017 and 2016, respectively. Total revenues consist of net sales from operations and other income and revenues. Eni's net sales from operations amounted to €75,822 million, €66,919 million and €55,762 million for the years ended December 31, 2018, 2017 and 2016, respectively, and its other income and revenues totaled €1,116 million, €4,058 million and €931 million, respectively, in these periods.

Net sales from operations

The table below sets forth, for the periods indicated, net sales from operations generated by each of Eni's business segments including intragroup sales, together with consolidated net sales from operations.

	Year ended December 31,		
	2018	2017	2016
	(€ million)		
Exploration & Production	25,744	19,525	16,089
Gas & Power	55,690	50,623	40,961
Refining & Marketing and Chemicals	25,216	22,107	18,733
Corporate and other activities	1,589	1,462	1,343
Consolidation adjustments(1)	(32,417)	(26,798)	(21,364)
NET SALES FROM OPERATIONS	75,822	66,919	55,762

(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 35 – of the Notes on Consolidated Financial Statement for a breakdown of intragroup sales by segment for the reported years.

2018 compared to 2017. Eni's net sales from operations (revenues) for 2018 (€75,822 million) increased by €8,903 million from 2017 (or up by 13.3%) primarily reflecting the recovery in commodity prices.

Revenues generated by the Exploration & Production segment (€25,744 million) increased by €6,219 million (or up by 31.9%). This was due to higher average realizations on equity hydrocarbons (oil realizations up by 30.8%; gas realizations up by 41% on average in dollar terms) driven by increasing prices for the marker Brent (up by 30.9%) and better gas prices due to tighter gas markets in certain geographies and the ramp-up of production with higher-than-average gas realizations.

Revenues generated by the Gas & Power segment (€55,690 million) increased by €5,067 million (or up by 10%). The increase reflected higher natural gas and power prices, as well as increased revenues from trading activity due to higher oil and products selling prices.

Revenues generated by the Refining & Marketing and Chemical segment (€25,216 million) increased by €3,109 million (or up by 14.1%) mainly in the Refining & Marketing business with an increase of €2,958 million due to higher commodity prices. The average selling prices of gasoline and gasoil reported an increase of 14% and 30%, respectively. Revenues generated in the Chemical segment slightly increased (up by €272 million) boosted by the increase in average selling prices as well as by higher volumes sold (up by 6%).

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2017 compared to 2016. Eni's net sales from operations (revenues) 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%).

Other income and revenues

2018 compared to 2017. Eni's other income and revenues amounted to €1,116 million in the full year 2018 and mainly related to the gain on the divestment of a 10% interest in the Zohr project. The reduction of €2,942 million from the full year 2017 is due to the gains on disposals recorded in 2017 on the sale 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).

2017 compared to 2016. Eni's other income and revenues 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).

b) Operating expenses

The table below sets forth the components of Eni's operating expenses for the periods indicated.

	Year ended December 31,		
	2018	2017	2016
	(€ million)		
Purchases, services and other	55,622	51,548	43,278
Impairment losses (impairment reversals) of trade and other receivables, net	415	913	846
Payroll and related costs	3,093	2,951	2,994
Operating expenses	59,130	55,412	47,118

2018 compared to 2017. Operating expenses for 2018 (€59,130 million) increased by €3,718 million y-o-y, up by 6.7%, 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 €705 million relating mainly to environmental provisions and the recognition of losses on certain contractual and commercial disputes. Payroll and related costs (€3,093 million) increased by €142 million from 2017, up by 4.8%, mainly due to the increase in average wages and higher provisions for redundancy incentives relating to an early retirement program in the Eni gas e luce subsidiary. These increases were partly offset by a reduction in the average number of employees outside Italy and the appreciation of the euro against the US dollar.

2017 compared to 2016. Operating expenses 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

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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.

c) Depreciation, depletion, amortization, impairment losses (impairment reversals) net and write-off

The table below sets forth a breakdown of depreciation, depletion, amortization, impairment losses (impairment reversals) net and write-off for the periods indicated.

	Year ended December 31,		
	2018	2017	2016
	(€ million)		
Exploration & Production	6,152	6,747	6,772
Gas & Power	408	345	354
Refining & Marketing and Chemicals	399	360	389
Corporate and other activities	59	60	72
Impact of unrealized intragroup profit elimination(1)	(30)	(29)	(28)
Total depreciation, depletion and amortization	6,988	7,483	7,559
Impairment losses	1,292	862	1,067
Reversals of impairment losses	(426)	(1,087)	(1,542)
Write-off	100	263	350
Total depreciation, depletion, amortization, impairment losses (impairment reversals), net and write off	7,954	7,521	7,434

(1)
This item concerned mainly intra-group sales of goods and capital, recorded at period end in the assests of the purchasing business segment.

2018 compared to 2017. In 2018, depreciation, depletion and amortization charges (€6,988 million) decreased by €495 million from 2017, or 6.6%, mainly in the Exploration & Production segment (a decrease of €595 million) due to the classification of Eni Norge subsidiary as held for sale in accordance to IFRS 5 from the second half of 2018 due to the pending business combination with Point Resources. After Eni Norge was classified as held for sale in accordance to IFRS 5, amortization ceased. The total amount of depreciation, depletion and amortization was also positively impacted by the appreciation of the euro, partly offset by fields started-up and new projects ramp-up.

In 2018, the Group recorded impairment losses at property, plant and equipment for a total amount of €1,292 million, mainly relating to: (i) impairment losses of oil&gas assets driven by a lower-than-expected performance at certain fields in Congo and in the USA, and the impairment of a mineral interest reflecting a worsening operating environment (for a total of €1,025 million), (ii) the write-down of capital expenditure relating to certain Cash Generating Units in the R&M business, which were impaired in previous reporting periods and continued to lack any profitability prospects (€156 million). These negatives were partly offset by the reversal of prior-year impairment losses at certain oil&gas assets driven by an improved outlook for gas prices in Italy and a reduction in the discount rate due to a reduced country-risk premium (for a total amount of €299 million) and at certain transportation activities outside Italy due to the reduction of the country risk premium factored in the discount rate (€66 million).

The write-off amounting to €100 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 Vietnam and Morocco.

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

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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.

d) Operating profit (loss) by segment

The table below sets forth Eni's operating profit by business segment for the periods indicated.

	Year ended December 31,		
	2018	2017	2016
	(€ million)		
Exploration & Production	10,214	7,651	2,567
Gas & Power	629	75	(391)
Refining & Marketing and Chemicals	(380)	981	723
Corporate and other activities	(691)	(668)	(681)
Impact of unrealized intragroup profit elimination	211	(27)	(61)
Operating profit (loss)	9,983	8,012	2,157

The table below sets forth operating profit (loss) for each of Eni's business segments as a percentage of each segment's net sales from operations (including intragroup sales) for the periods presented.

	Year ended December 31,		
	2018	2017	2016
	(%)		
Exploration & Production	39.7	39.2	16.0
Gas & Power	1.1	0.1	(1.0)
Refining & Marketing and Chemicals	(1.5)	4.4	3.9
Group	13.2	12.0	3.9

Exploration & Production. In 2018, the Exploration & Production segment reported an operating profit of €10,214 million, with an increase of €2,563 million compared to the operating profit of €7,651 million reported in 2017. The better performance was driven by higher realized prices on equity hydrocarbons and production increases, with the latter boosted by the increased contribution of barrels with higher-than-average profitability.

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The operating result of the Exploration & Production segment included the gain on the disposal of interests in the Shorouk and Nour concessions located offshore Egypt (€339 million, net of assignment bonus and other charges) and benefitted from the suspension for a semester of amortization charges at the held-for-sale subsidiary Eni Norge due to the pending business combination with Point Resources, which closed at year-end. Assets or disposal group held for sale are not to be depreciated or amortized in accordance to IFRS 5.

These positives were partly offset by an allowance for doubtful accounts as part of a dispute to recover credits for investments due by a State counterparty to align the recoverable amount with the expected outcome of an ongoing renegotiation (€158 million), environmental charges and a charge taken in connection with the outcome of an arbitration proceeding relating a long-term contract to purchase regasification services, which resulted in the termination of the contract and of the related annual fees charged to Eni. It also awarded the counterparty equitable compensation of €289 million. Finally, the result was negatively affected by currency translation effects being the EUR/USD dollar exchange rate up by 4.5% compared to 2017.

In 2018, the Company's liquids and gas realizations increased on average by 35.4% in dollar terms, driven by a strengthened petroleum environment. Eni's average oil realizations increased on average by 30.8%, in line with the increase recorded in international oil prices for the Brent market benchmark (up by 31% for the year). Eni's average gas realizations increased by 41% driven by the ramp-up of production with a higher-than-average sale price.

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.

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 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 non-core 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 €10,850 million, with an increase of €5,677 million from 2017, or 109.7%. The increase was driven by a recovery in the commodity environment which drove increased oil&gas realizations in dollar terms (up by 35.4% on average), production growth and an improved underlying performance driven by a better sales mix on the back of the growth of production with higher-than-average profitability.

	Year ended December 31,		
	2018	2017	2016
Exploration & Production	(€ million)		
GAAP operating profit (loss)	10,214	7,651	2,567
Net gains on disposal of assets	(442)	(3,269)	(2)
Impairment losses (impairment reversals), net	726	(158)	(677)
Environmental provisions	110	46	
Risk provisions	360	366	105
Reclassification of currency derivatives and translation effects to management measure of business performance	(6)	(68)	(3)
Valuation allowance of disputed receivables and others	158	442	410
Reinstatement of Eni Norge amortization charges	(375)		
Other	105	163	94
Total gains and charges	636	(2,478)	(73)
Non-GAAP operating profit (loss)	10,850	5,173	2,494

Gas & Power. In 2018, the Gas & Power segment reported an operating profit of €629 million, an increase of €554 million compared to the profit of €75 million of the previous year. This improvement was driven by the overall restructuring of all the business lines, effective management of flexibilities associated with the portfolio of long-term gas contracts, optimization in the power business and in logistics, as well as growth in the LNG business leveraging its integration with the E&P segment.

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 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 €543 million, with an increase of €329 million from 2017, reflecting the strong progress in restructuring all business lines. The main drivers of the operational improvements were the growth in LNG sales and margins as well as power and logistic optimizations. Furthermore, the favorable trends registered in the first nine months in the natural gas wholesale market enabled the Company to extract value from the flexibilities associated with the portfolio of long-term supply contracts, such as the opportunity to sell additional volumes beyond the minimum take at long-term contracts in case of favorable demand trends like those that occurred during the first nine months thanks to a tight gas market (i.e. the flexibility associated with the possibility to lift additional gas volumes from a long-term contract once the minimum annual take has been fulfilled up to the annual contractual quantity). Also the retail business showed an improved performance driven by lower credit losses due to the initiatives designed to de-risk the customer portfolio, as well as efficiency gains.

The items excluded from GAAP operating profit in determining the Non-GAAP measure of profitability 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

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(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, although the Group classifies within net finance expense those gains and losses on currency derivatives, as well as on the alignment of trade 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 currency differences at our dollar-denominated trade payables and receivables as part of the underlying business performance.

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,		
	2018	2017	2016
Gas & Power	(€ million)		
GAAP operating profit (loss)	629	75	(391)
(Profit) loss on inventory			90
Impairment losses (impairment reversals), net	(71)	(146)	81
Environmental provisions	(1)		
Allowance for doubtful accruals in the retail G&P			17
Provision for redundancy incentives	122	38	4
Fair value gains/losses on commodity derivatives	(156)	157	(443)
Reclassification of currency derivatives and translation effects to management measure of business performance	112	(171)	(19)
Estimated revenues accruals in the retail G&P		64	161
Revision of estimated revenues accruals in the retail G&P (difference between incurred loss vs. expected loss model)		223	
Other	(92)	(26)	110
Total gains and charges	(86)	139	1
Non-GAAP operating profit (loss)	543	214	(390)

Refining & Marketing. In 2018, the Refining & Marketing and Chemicals segment reported an operating loss of €380 million, reversing the operating profit of €981 million reported in 2017, driven by a challenging trading environment because of rapidly-escalating oil-based feedstock costs which were not fully recovered in the final prices of products due to competitive pressure from more efficient producers and a slowdown in end-markets, leading to a squeeze in margins.

Furthermore, due to a sharp decline in crude oil and products prices recorded in the final weeks of 2018, inventories were aligned to their net realizable values recording an estimated loss of €234 million compared to an inventory profit of €213 million a year ago. Impairment losses and environmental provisions negatively affected the reported results by approximately €250 million.

The refining activity was negatively affected by a 26% decline in refining margins and by longer plant standstills. The oxygenated business was penalized by downtime at certain assets due to prolonged maintenance activities. These negative trends were offset by plant and supply optimizations, as well as by higher margins on green throughputs.

Marketing activities reported an improved performance both in the retail and wholesale segments also leveraging on effective commercial initiatives to support margins and on efficiency actions.

The Chemical business was affected by the worsening trading environment characterized by sharply higher supply costs of oil-based feedstock in the first ten months that were not recovered in sale prices, by competitive pressures and by a demand slowdown in the last part of the year, mainly in the polyethylene

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segment, which resulted in a strong contraction of the benchmark margin of cracker (down by 11%) and polyethylene margins (down by 69%), as well as, by the fact that the first half of 2017 benefitted from particularly high prices of intermediates (butadiene and benzene) due to contingent factors.

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.

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.

In addition to the inventory holding loss, the non-core items of this segment for the year 2018 also comprised 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 (€156 million) and environmental provisions (€165 million).

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 non-core 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 €380 million, with a decrease of €611 million from 2017 due to the industrial trends described above.

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	Year ended December 31,		
	2018	2017	2016
Refining & Marketing and Chemicals	(€ million)		
GAAP operating profit (loss)	(380)	981	723
(Profit) loss on inventory	234	(213)	(406)
Environmental provisions ond other costs	243	136	104
Impairment losses (impairment reversals), net	193	54	104
Net gains on disposal of assets	(9)	(13)	(8)
Provision for redundancy incentives	8	(6)	12
Other	91	52	54
Total gains and charges	760	10	(140)
Non-GAAP operating profit (loss)	380	991	583

Corporate and Other activities. These activities are mainly cost centers comprising holdings, financing and treasury activities in support of operating subsidiaries, central functions like information technology, legal counselling, human resources, insurance activitiesm general and administrative support, 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 €691 million in 2018, an increase of €23 million from 2017, or 3.4%.

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.

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,		
	2018	2017	2016
	(€ million)		
Gain (loss) on derivative financial instruments	(307)	837	(482)
of which			
– Derivatives on exchange rate	(329)	809	(494)
– Derivatives on interest rate	22	28	(12)
Exchange differences, net	341	(905)	676
Net income from financial activities held for trading	32	(111)	(21)
Interest income due to banks	18	12	15
Finance expense from banks on short and long-term debt	(685)	(751)	(757)
Finance expense due to the passage of time (accretion discount)	(249)	(264)	(312)
Other finance income and expense, net	(173)	(127)	(110)
	(1,023)	(1,309)	(991)
Finance expense capitalized	52	73	106
NET FINANCE EXPENSES	(971)	(1,236)	(885)

2018 compared to 2017. In 2018, net finance expenses were €971 million, lower by €265 million than in 2017. This reduction was due to lower interest expense on short and long-term debt, which reflected the €2,627 million decrease in net borrowings. Like in the comparative periods, losses on exchange rate derivatives were offset by gains on currency translation at dollar-denominated payables and receivables accrued by Italian subsidiaries, as the Group normally pools different exposures to the currency risk retained by operating subsidiaries and then hedges the Group net exposure to the risk.

Other net finance income and expense were a loss of €173 million driven by the impairment of operating financing receivables due by an equity-accounted entity, which engaged in the execution of an exploration projects that was written-off due to an unsuccessful outcome.

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

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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.

f) Net income from investments

2018 compared to 2017. In 2018 the Group reported a net profit from investments of €1,095 million and related to:

i).
dividends of €231 million paid by minor investments in certain entities which were designated at fair value through OCI under IFRS 9 except for dividends which are recorded through profit. These entities mainly comprised Nigeria LNG Ltd (€187 million, where Eni has an interest of 10.4%) and Saudi European Petrochemical Co (€35 million, where Eni has an interest of 10%);

ii).
other net gains (€910 million) including the net gain on the Vår Energi business combination (approximately €890 million);

iii).
the impairment reversal (€262 million) at the Angola LNG equity-accounted entity due to improved project economics.

These gains were partly offset by Eni’s share of losses incurred by equity-accounted investments (€430 million) driven by losses recorded by the Saipem joint venture due mainly to the incurrence of impairment losses and restructuring charges by the investee, and by an impairment loss of a joint venture which engaged in an oil project due to the downward reserve revision on the back of a deteriorated operating environment.

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.

g) Taxes

2018 compared to 2017. In 2018, income taxes amounted to €5,970 million, up by €2,503 million compared to 2017, or 72,2%. This increase reflected higher income before taxes which was €10,107 million, almost doubling compared to 2017.

Tax rate was approximately 59% compared to 51% reported in 2017, reflecting lower gains free of taxes or subject to a lower tax rate compared to the Group average tax rate. Excluding those non-core effects the Group tax rate was substantially in line with 2017 due to higher contribution of segments other than the E&P, the effect of which offset the increased E&P tax rate due to the recognition of lower deferred tax assets on projects and the fact that the loss incurred at an equity-accounted exploration project was not deductible.

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 at 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.

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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.

Liquidity and capital resources

Eni's cash requirements for working capital, dividends to shareholders, capital expenditures and acquisitions over the past three years were financed primarily by a combination of funds generated from operations, borrowings and divestments of 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,		
	2018	2017	2016
	(€ million)		
Net profit (loss)	4,137	3,377	(1,044)
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	7,657	8,720	7,773
– net gains on disposal of assets	(474)	(3,446)	(48)
– dividends, interest, taxes and other changes	6,168	3,650	2,229
Changes in working capital related to operations	1,632	1,440	2,112
Dividends received, taxes paid, interest (paid)	(5,473)	(3,624)	(3,349)
Net cash provided by operating activities	13,647	10,117	7,673
Capital expenditures	(9,119)	(8,681)	(9,180)
Acquisition of investments and businesses	(244)	(510)	(1,164)
Disposals of consolidated subsidiaries, businesses, tangible and intagible assets and investments	1,242	5,455	1,054
Other cash flow related to investing activities (*) (**)	585	(32)	5,736
Changes in short and long-term finance debt	320	(1,712)	(766)
Dividends paid and changes in non-controlling interests and reserves	(2,957)	(2,883)	(2,885)
Effect of changes in consolidation, exchange differences and cash and cash equivalents	18	(65)	(3)
Change in cash and cash equivalent for the year	3,492		