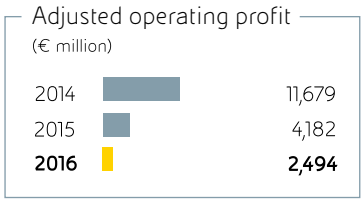
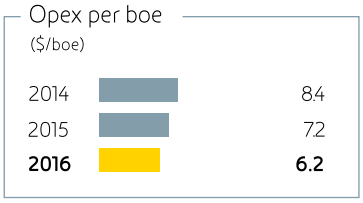
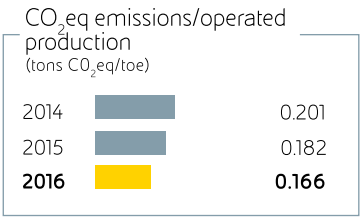
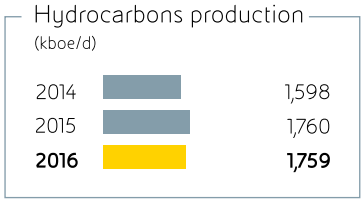
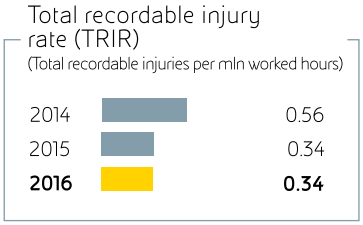
Exploration & Production

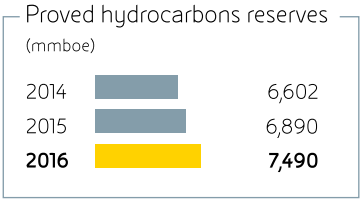












1.1 billion boe of discovered resources
continuing strong exploration track record

organic reserves replacement ratio of **193%**

-9% improving upstream GHG emissions, exceeding the target

-14%
opex decrease due to efficiency improvements

sale of **40%** in **Zohr** Our dual exploration model proved to be successful

Improved prospects of **organic production growth** notwithstanding a 17% capex reduction vs 2015

Performance of the year

- In 2016, safety performance continued on a positive trend, with a total recordable injury rate of 0.34 (unchanged from 2015). Eni is engaged in maintaining a high safety standard in each of its operations leveraging also on continuous HSE awareness programs by means of specific projects.
- Greenhouse gas emissions decreased by 11% compared to the previous year leveraging on the continuous improvements in energy efficiency, logistics optimization and initiatives to contain fugitive emissions, in particular developed for the 2016 in Egypt, Kazakhstan, the United Kingdom, Ecuador and United States. In March 2016, Goliat platform started-up, through advanced technology solutions thus contributing to the combustion emissions containment. The trend of GHG emission index compared to operated gross hydrocarbon production was positive with a reduction of 9%. This performance is better than the 2016 full year target.
- Water reinjection continues to achieve an excellent industry performance (58% in 2016), leveraging on the continuous campaign started in certain operational plants, in particular in Ecuador, Egypt and Congo in the full year.
- For the full year 2016, the E&P segment reported a decline of 40% in adjusted operating profit due to lower realization on commodities in dollar terms (down by 20%) as well as the Val d'Agri shutdown, which lasted four months and half. These effects were only partially offset by higher production in other areas and efficiency improvements with lower opex to 6.2 $/boe (down by 14% from 7.2 $/boe reported in 2015) and DD&A[1] (down by 16% from 2015).
- 2016 oil and natural gas production was 1,759 kboe/d, in line with 2015, in spite of the Val d'Agri shutdown. Production start-ups and ramp-ups added approximately 280 kboe/d in 2016. 2017 expected production will achieve a record of 1.84 million boe/d increasing by approximately 5% from 2016.

(1) Depreciation, depletion and amortization.

- Estimated net proved reserves at December 31, 2016 amounted to 7.5 bboe based on a reference Brent price of $42.8 per barrel. Organic reserves replacement ratio surged to 193%, the best ever performance in Eni's history. The 2016 reserves replacement ratio remains very robust at 139% also considering the 40% sale of Zohr on a pro forma basis. The reserves life index was 11.6 years (10.7 years in 2015).

Exploration activity

- Eni signed two agreements with major international players in the oil&gas business for the disposal of a 40% interest in the giant discovery Zohr, located in the operated block of Shoruk (Eni 100%) in Egypt. These transactions proved the validity of Eni's "dual exploration model" which is targeting simultaneously the fast-track development of discovered resources and the partial dilution of the high stakes retained in exploration leases to monetize in advance part of discovered volumes and reduce outlay in development expenditures. These agreements have economic efficacy from January 1, 2016 and contemplate the reimbursement to Eni of capex incurred until the closing date.
  The new partners have the option to acquire a further 5% stake at the same terms defined in the agreements. The first transaction closed on February 2017 following approval by the Egyptian authorities; the second one is expected to close by the first half of 2017. The total consideration of the deal amounts to approximately €2 billion as of January 1, 2017, including the reimbursement of costs incurred by Eni in 2016. Eni, applying its dual exploration model, has already disposed stakes worth €5.4 billion since 2013.
- Continuing strong exploration track record. Discovered 1.1 billion boe of additional resources at a cost of 0.6 $/boe. Additions to the Company's resources backlog were 3.4 billion boe in the latest 3 years, at a cost of 1 $/boe. Promising new prospects to be drilled in the future years.
- In Morocco, Eni signed a Farm-Out Agreement (FOA) with Chariot Oil&Gas that includes the operatorship to Eni and a 40% stake enter into Rabat Deep Offshore exploration permits I-VI offshore Morocco.
- In Montenegro, Eni was awarded a new exploration license related to four offshore blocks, covering an area of 1,228 square kilometers. The license will be operated by Eni, which will retain a 50% interest, in joint venture with Novatek.
- Finalized in March 2017, a farm-in agreement to acquire a 50% interest of Block 11, offshore Cyprus, which will be operated by Total. The exploration area covers 2,215 square kilometers, nearby the Zohr discovery.
- Signed four agreements with the Bahrain national oil company to study and assess the potential of certain exploration and production assets in the Country. At the end of the studies, Bahrain Authorities and Eni will evaluate together the possibility of future initiatives for further developments of the Country's energy resources.
- The exploration portfolio was renewed by means of new exploration acreage covering approximately 10,500 square kilometers net to Eni in legacy areas such as, in particular, Egypt, Ghana, Norway and the United Kingdom, as well as in the high potential areas such as Montenegro and Morocco, as mentioned above.
- In 2016, exploration expenditure amounted to €417 million, mainly related to the completion of the 16 new exploratory wells (10.2 net to Eni). Commercial success rate recorded an outstanding industry performance reporting a 50% net to Eni. In addition, 79 exploratory drilled wells are in progress at year end (40 net to Eni).

Sustainability and portfolio developments

- Achieved start-ups in significant projects, such as:
  - the Goliat Norwegian fields (Eni operator with a 65% interest) in the Barents Sea, achieving a production plateau of 100 kboe/d (65 kboe/d net to Eni);
  - production re-start of the Kashagan field (Eni's interest 16.81%) with the fully replacement of the damaged pipelines. Production capacity of 370 kbbl/d is expected by the end of 2017;
  - start-up of M'Pungi and M'Pungi North within the West Hub Development project in the offshore Block 15/06 (Eni operator with a 36.84% interest) in Angola, with a production ramp-up of approximately 81 kbbl/d in the area;
  - in February 2017, start-up of the East Hub Development project in the Block 15/06, five months earlier than scheduled and with a time-to-market among the best in the industry. The East Hub project will develop the reservoir in the north-eastern area by means of a development program similar to the West Hub;
  - the Great Nooros Area (Eni's interest 75%) in Egypt, achieving a peak production of 85.5 kboe/d net to Eni. This record-setting production level was reached in just 13 months after the discovery and ahead of schedule. In addition, thanks to the mature operating environment and the conventional nature of the project, production costs are among the lowest in Eni's portfolio.
- Progressed construction activities at our development projects expected to come on stream in 2017 (Jangkrik in Indonesia, OCTP oil in Ghana as well as Zohr and East Hub, as discussed above). These projects, together with the ramp-up of 2016 new production from Kashagan and Goliat, will strongly contribute to the cash generation in 2017 and following years.

- Signed in Mozambique a binding agreement between the partners of the Area 4 and BP for the sale, over a 20-year period, of approximately 3.3 million tons of LNG per annum (corresponding to about 177 bcf), which will be produced at the Coral South Floating facility. The agreement is a fundamental step towards achieving the Final Investment Decision of the project, targeting production of 5 trillion cubic feet of gas.
- In March 2017, ExxonMobil and Eni signed sale and purchase agreement to acquire a 25% indirect interest in the Area 4 block, offshore Mozambique. The agreed terms include a cash price of approximately $2.8 billion. The acquisition will be completed subject to satisfaction of certain conditions precedent, including clearance from Mozambican and other regulatory authorities.
- Eni's cooperation framework supports local development, seeks to minimize socio-economic gaps and involves all stakeholders. Eni is engaged in energy production for the domestic market, in the spread of access to electricity, diversification of energy mix and of local economies, in the supply know-how and technology as well as in the support of local development in health and education.
- Eni's long-term integrated strategy for achieving decarbonization targets is based on lowering CO_2 emissions and enhancing efficiency in all Eni's activities, keeping low-carbon portfolio projects and supporting the natural gas to feed power generation and transport.
- Development expenditure was €7,770 million (down by 16.8% vs. 2015) to fuel the growth of major projects and to maintain production plateau particularly in Egypt, Angola, Kazakhstan, Indonesia, Iraq, Ghana and Norway.
- In 2016, overall R&D expenditure of the Exploration & Production segment amounted to €62 million (€78 million in 2015).

Strategy

Upstream growth model will continue to focus on conventional assets, which will be organically developed, with a large resource base and a competitive cost structure, which make them profitable even in a low price environment.
The sizeable exploration successes of the last years have increased the Company's resource base, contributing to the Company's value generation through the early monetization of the discovered resources in excess of the target replacement ratio.
Eni's top priorities are the increase and valorisation of discovered resources and a growing cash generation.
The drivers to target the increase and valorisation of discovered resources are: (i) focusing of exploration activities on appraisal programmes at the recent discoveries (Egypt, Angola, Norway and Mexico), near-field initiatives and incremental activities in legacy areas and nearby to fields already under development, with the objective of delivering 2-3 billion boe of discovered resources; (ii) renewal of the portfolio of exploration leases by focusing on high materiality play; and (iii) fast-track development of discovered resources by optimizing the time-to-market and exercising tight control on project execution.
Cash generation will be driven by: (i) production growth at an annual average rate of 3% net of disposal, leveraging on a robust pipeline of projects in core areas, including also contractual revisions with oil-producing countries and strictly monitoring of non-operated activities. New field start-ups, production ramp-ups and continuing production optimization will add approximately 850 kboe/d in 2020. Main start-ups are the Jangkrik project (Eni operator with a 55% interest) in Indonesia, the East Hub project in Angola, the oil and gas development of the Offshore Cape Three Points project (Eni operator with a 47.22% interest) in Ghana as well as accelerated start-up of the giant offshore Zohr discovery and continuous start-up of the discoveries in the Great Nooros Area in Egypt; (ii) project modularization and phasing which will enable the Company to reduce financial exposure and to accelerate production start-ups; (iii) strengthened efficiency by means of several initiatives to reduce operating costs, to be achieved also by renegotiating the supply of field services and goods; (iv) focusing on working capital driven by an optimised exposure to third parties and joint venture partners and decreasing products inventories; and (v) early monetization of part of discovered volumes.
Eni acknowledges that the upstream performance could be adversely impacted in the short-to-medium-term by a number of risks: (i) the commodity risk related to crude oil prices. Eni is planning to mitigate this risk by implementing initiatives of rationalization and optimization, the renegotiation of contractual terms with contractors to align costs of field services and goods to the changed market conditions. In 2017-20 plan period, Eni estimates a decrease of 13% of capital expenditure net of exchange rate effects versus the previous four-year plan due to a reduction in exploration expenditure which will be focused on near-field and appraisal activities, the re-phasing of projects yet to be sanctioned with lower contribute to production and cash generation in the four-year plan period, the reduction of non-operated project, strong focus on service contract renegotiations and the sale of 40% interest in Zohr project; (ii) the political risk due to social and political instability in certain countries of operations. A major part of Eni's activities are currently located in countries that are far from high-risk areas and Eni plans to grow mainly in countries with low-mid political risk (approximately 85% of the capital expenditure of the four-year plan); (iii) risk related to the growing complexity of certain projects due to technological and logistic issues. Eni plans to counteract those risks by strict selection of adequate contractors, tight control of the time-to market and the retaining of the operatorship in a large number of projects (76% of production related to operated projects portfolio in 2020); and (iv) the technical risk related to the execution of drilling activities at deep waters, high pressure/high temperature and PEE (Potential Economic Impact) wells. In 2017-20 plan period, Eni plans to decrease the drilling of critical wells (19% of overall planned drilling activities in 2017 to 15% in 2020; 16% on average in the four-year plan) and to increase operatorship of critical projects (63% of planned activity) ensuring better direct control and deploying its high operational standards.
The business sustainability in the short-to-long-term remains a key factor to achieve the strategic goals also through the increasing stakeholders engagement and continuous relations with local authorities and including: (i) a decrease of more than 20% of process flaring in 2020 versus 2014, in line with target of zero routine flaring in 2025; (ii) the water re-injection program with the completion of relevant projects in the four-year plan to achieve target of 72% in 2020; and (iii) the carbon footprint reduction focusing on gas initiatives and energy savings.

Reserves

Overview

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

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

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

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

Reserves governance

Eni retains rigorous control over the process of booking proved reserves, through a centralized model of reserves governance. The Reserves Department of the Exploration & Production segment is entrusted with the task of: (i) ensuring the periodic certification process of proved reserves; (ii) continuously updating the Company's guidelines on reserves evaluation and classification and the internal procedures; and (iii) providing training of staff involved in the process of reserves estimation. Company guidelines have been reviewed by DeGolyer and MacNaughton (D&M), an independent petroleum engineering company, which has stated that those guidelines comply with the SEC rules[2]. 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 at the head office verifies the production profiles of such properties where significant changes have occurred; (iii) geographic area managers verify the commercial conditions and the progress of the projects; (iv) the Planning and Control Department provides the economic evaluation of reserves; and (v) the Reserves Department, through the Headquarter Reserves Evaluators (HRE), provides independent reviews of fairness and correctness of classifications carried out by the above mentioned units and aggregates worldwide reserves data.

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

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

Reserves independent evaluation

Since 1991, Eni has requested qualified independent oil engineering companies to carry out an independent evaluation[3] of part of its proved reserves on a rotational basis. The description of qualifications of the persons primarily responsible for the reserves audit is included in the third party audit report[4]. 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 economic value of Eni's equity reserves, actual prices applicable to hydrocarbon sales, price adjustments required by applicable contractual arrangements and other pertinent information are provided by Eni to third party evaluators.

In 2016, Ryder Scott Company, DeGolyer and MacNaughton and Gaffney, Cline & Associates provided an independent evaluation of approximately 41% of Eni's total proved reserves at December 31, 2016[5], confirming, as in previous years, the reasonableness of Eni

(2) The reports of independent engineers are available on Eni website eni.com section Publications/Integrated Annual Report 2016.
(3) From 1991 to 2002, DeGolyer and MacNaughton; from 2003, also Ryder Scott and from 2015, also Gaffney, Cline & Associates.
(4) The reports of independent engineers are available on Eni website eni.com section Publications/Integrated Annual Report 2016.
(5) Includes Eni's share of proved reserves of equity-accounted entities.

internal evaluation[5]. In the 2014-2016 three-year period, 94% of Eni total proved reserves were subject to an independent evaluation. As at December 31, 2016, the main Eni properties not subjected to independent evaluation in the last three years were Zubair (Iraq), Bu Attifel (Libya) and CAFC-MLE (Algeria).

Movements in estimated net proved reserves

Eni's estimated proved reserves were determined taking into account Eni's share of proved reserves of equity-accounted entities. Movements in Eni's 2016 estimated proved reserves were as follows:

(mmboe)	Consolidated subsidiaries	Equity-accounted entities	Total
Estimated net proved reserves at December 31, 2015	**5,975**	**915**	**6,890**
Extensions, discoveries, revisions of previous estimates and improved recovery, excluding price effect	1,327	(7)	1,320
Price effect	(73)	(3)	(76)
Reserve additions, total	1,254	(10)	1,244
Production of the year	(616)	(28)	(644)
Estimated net proved reserves at December 31, 2016	**6,613**	**877**	**7,490**
Reserves replacement ratio, organic (%)			**193**

Additions to proved reserves booked in 2016 were 1,244 mmboe and derived from: (i) extensions and discoveries were up by 887 mmboe, with major increases booked in Egypt; (ii) revisions of previous estimates were up by 355 mmboe mainly reported in Libya, Iraq and Kazakhstan; (iii) improved recovery were 2 mmboe mainly reported in Algeria and Norway. These increases compared to production of the year yielded an organic reserves replacement ratio[6] of 193%. In spite of lowered Brent price at $42.8 per barrel in 2016 ($54 per barrel in 2015), all sources additions were adversely affected by a downward revision of 76 mmboe, due to our having to remove certain volumes of reserves which have become uneconomical in that environment, which were partially offset by higher volume entitlements at our PSA contracts because of the cost recovery mechanism reflecting a lowered Brent price used in the reserves estimation process. Reserves life index was 11.6 years (10.7 years in 2015).

Proved undeveloped reserves

Proved undeveloped reserves as of December 31, 2016 totaled 3,215 mmboe. At year-end, proved undeveloped reserves of liquids amounted to 1,165 mmbbl, mainly concentrated in Africa and Asia. Proved undeveloped reserves of natural gas amounted to 11,184 bcf, mainly located in Africa and Americas. Proved undeveloped reserves of consolidated subsidiaries amounted to 1,040 mmbbl of liquids and 9,218 bcf of natural gas. In 2016, total proved undeveloped reserves increased by 348 mmboe mainly due to: (i) extensions and discoveries (up by 873 mmboe), in particular in Egypt due to final investment decision sanctioned for the Zohr discovery; (ii) revisions of previous estimates (up by 121 mmboe) mainly reported in Congo and Iraq; (iii) reclassification to proved developed reserves (down by 646 mmboe) mainly reported in Kazakhstan, Venezuela and Congo . During 2016, Eni converted 646 mmboe of proved undeveloped reserves to proved developed reserves due to the progress of development activities, production start-ups and project revisions. The main reclassifications to proved developed reserves related to the following fields/projects: Kashagan (Kazakhstan), Perla (Venezuela), Litchendjili (Congo), Zubair (Iraq) and Goliat (Norway). In 2016, capital expenditure amounted to approximately €7.5 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. Of the proved undeveloped reserves that have been reported for five or more years, the largest are related to forthcoming development phases of the Kashagan project in Kazakhstan (approximately 0.2 bboe) and certain assets in Venezuela (approximately 0.4 bboe) and in Iraq (approximately 0.2 bboe) as well as to certain Libyan gas fields (approximately 0.5 bboe) where development completion and production start-ups are planned according to the delivery obligations set forth in a long-term gas supply agreement currently in force. In order to secure fulfillment of the contractual delivery quantities in Libya, Eni will implement phased production start-up from the relevant fields which are expected to be put in production over the next several years.

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 453 mmboe from producing assets located mainly in Algeria, Australia, Egypt, Libya, Nigeria, Norway and Venezuela. The sales contracts contain a mix of fixed and variable pricing formulas that are generally referenced to the market price for crude oil, natural gas or other petroleum products. Management believes it can satisfy these contracts from quantities available from production of the Company's proved developed reserves and supplies from third parties based on existing contracts. Production is expected to account for approximately 86% of delivery commitments. Eni has met all contractual delivery commitments as of December 31, 2016.

(5) Includes Eni's share of proved reserves of equity-accounted entities.
(6) Organic ratio of changes in proved reserves for the year resulting from revisions of previously reported reserves, improved recovery, extensions and discoveries, to production for the year. All sources ratio includes sales or purchases of minerals in place. A ratio higher than 100% indicates that more proved reserves were added than produced in a year. The Reserves Replacement Ratio is not an indicator of future production because the ultimate development and production of reserves is subject to a number of risks and uncertainties. These include the risks associated with the successful completion of large-scale projects, including addressing ongoing regulatory issues and completion of infrastructure, as well as changes in oil and gas prices, political risks and geological and environmental risks.

Estimated net proved hydrocarbons reserves

	Liquids (mmbbl)	Natural gas (bcf)	Hydrocarbons (mmboe)	Liquids (mmbbl)	Natural gas (bcf)	Hydrocarbons (mmboe)	Liquids (mmbbl)	Natural gas (bcf)	Hydrocarbons (mmboe)
Consolidated subsidiaries	2014			2015			2016		
Italy	**243**	**1,432**	**503**	**228**	**1,304**	**465**	**176**	**977**	**354**
Developed	*184*	*1,192*	*401*	*171*	*1,051*	*362*	*132*	*845*	*287*
Undeveloped	*59*	*240*	*102*	*57*	*253*	*103*	*44*	*132*	*67*
Rest of Europe	**331**	**1,171**	**544**	**305**	**1,044**	**495**	**264**	**878**	**426**
Developed	*174*	*887*	*335*	*237*	*919*	*404*	*228*	*801*	*374*
Undeveloped	*157*	*284*	*209*	*68*	*125*	*91*	*36*	*77*	*52*
North Africa	**776**	**5,291**	**1,740**	**821**	**4,798**	**1,694**	**735**	**9,258**	**2,432**
Developed	*521*	*2,110*	*904*	*542*	*2,566*	*1,010*	*492*	*2,531*	*957*
Undeveloped	*255*	*3,181*	*836*	*279*	*2,232*	*684*	*243*	*6,727*	*1,475*
of which:									
Egypt							**281**	**5,520**	**1,293**
Developed							*205*	*799*	*352*
Undeveloped							*76*	*4,721*	*941*
Sub-Saharan Africa	**739**	**2,744**	**1,239**	**787**	**2,714**	**1,282**	**809**	**2,767**	**1,317**
Developed	*470*	*1,271*	*702*	*511*	*1,390*	*764*	*507*	*1,651*	*809*
Undeveloped	*269*	*1,473*	*537*	*276*	*1,324*	*518*	*302*	*1,116*	*508*
Kazakhstan	**697**	**2,049**	**1,069**	**771**	**2,354**	**1,198**	**767**	**2,485**	**1,221**
Developed	*306*	*1,553*	*589*	*355*	*1,830*	*689*	*556*	*2,239*	*966*
Undeveloped	*391*	*496*	*480*	*416*	*524*	*509*	*211*	*246*	*255*
Rest of Asia	**131**	**846**	**285**	**262**	**878**	**422**	**307**	**1,003**	**491**
Developed	*64*	*261*	*112*	*126*	*185*	*159*	*124*	*280*	*175*
Undeveloped	*67*	*585*	*173*	*136*	*693*	*263*	*183*	*723*	*316*
Americas	**147**	**468**	**232**	**189**	**439**	**269**	**163**	**353**	**227**
Developed	*116*	*393*	*188*	*149*	*373*	*217*	*143*	*338*	*205*
Undeveloped	*31*	*75*	*44*	*40*	*66*	*52*	*20*	*15*	*22*
Australia and Oceania	**13**	**807**	**160**	**9**	**771**	**150**	**9**	**741**	**145**
Developed	*12*	*675*	*135*	*9*	*585*	*115*	*8*	*559*	*111*
Undeveloped	*1*	*132*	*25*		*186*	*35*	*1*	*182*	*34*
Total consolidated subsidiaries	**3,077**	**14,808**	**5,772**	**3,372**	**14,302**	**5,975**	**3,230**	**18,462**	**6,613**
Developed	***1,847***	***8,342***	***3,366***	***2,100***	***8,899***	***3,720***	***2,190***	***9,244***	***3,884***
Undeveloped	***1,230***	***6,466***	***2,406***	***1,272***	***5,403***	***2,255***	***1,040***	***9,218***	***2,729***
Equity-accounted entities									
North Africa	**14**	**15**	**16**	**13**	**13**	**14**	**13**	**15**	**14**
Developed	*13*	*15*	*15*	*13*	*13*	*14*	*13*	*15*	*14*
Undeveloped	*1*		*1*						
Sub-Saharan Africa	**17**	**351**	**81**	**16**	**387**	**87**	**15**	**368**	**82**
Developed	*7*	*89*	*23*	*6*	*85*	*22*	*8*	*104*	*26*
Undeveloped	*10*	*262*	*58*	*10*	*302*	*65*	*7*	*264*	*56*
Rest of Asia	**1**	**18**	**5**		**12**	**4**		**4**	**2**
Developed		*10*	*3*		*9*	*2*		*4*	*2*
Undeveloped	*1*	*8*	*2*		*3*	*2*			
Americas	**117**	**3,353**	**728**	**158**	**3,581**	**810**	**140**	**3,484**	**779**
Developed	*26*	*6*	*26*	*29*	*1,295*	*265*	*22*	*1,782*	*349*
Undeveloped	*91*	*3,347*	*702*	*129*	*2,286*	*545*	*118*	*1,702*	*430*
Total equity-accounted entities	**149**	**3,737**	**830**	**187**	**3,993**	**915**	**168**	**3,871**	**877**
Developed	***46***	***120***	***67***	***48***	***1,402***	***303***	***43***	***1,905***	***391***
Undeveloped	***103***	***3,617***	***763***	***139***	***2,591***	***612***	***125***	***1,966***	***486***
Total including equity-accounted entities	**3,226**	**18,545**	**6,602**	**3,559**	**18,295**	**6,890**	**3,398**	**22,333**	**7,490**
Developed	***1,893***	***8,462***	***3,433***	***2,148***	***10,301***	***4,023***	***2,233***	***11,149***	***4,275***
Undeveloped	***1,333***	***10,083***	***3,169***	***1,411***	***7,994***	***2,867***	***1,165***	***11,184***	***3,215***

Oil and natural gas production

In 2016, oil and natural gas production[7] averaged 1,759 kboe/d, in line with 2015, in spite of Val d'Agri shutdown. New fields' start-ups and production ramp-ups at fields started up in 2015 mainly in Angola, Egypt, Kazakhstan, Norway and Venezuela as well as increased production in Iraq were partly offset by planned facilities downtime, mainly in the United Kingdom, and the mature fields declines. The share of oil and natural gas produced outside Italy was 92% (90% in the full-year 2015).
Liquids production (878 kbbl/d) decreased by 30 kbbl/d, or 3.3%, due to the production shutdown in the Val d'Agri profit center, planned facilities downtime and the mature fields decline. These negatives were partially offset by new fields start-ups and production ramp-ups in particular in Angola, Kazakhstan and Norway as well as higher production in Iraq.

Natural gas production (4,807 mmcf/d) increased by 126 mmcf/d, or 2.3%. Higher production in Egypt and Venezuela were partially offset by planned facilities downtime and the decline of mature fields.
Oil and gas production sold amounted to 608.6 mmboe. The 35.2 mmboe difference over production (643.8 mmboe) reflected volumes of natural gas consumed in operations (32.1 mmboe), changes in inventories and other factors. Approximately 68% of liquids production sold (320 mmbbl) was destined to Eni's mid-downstream sectors. About 22% of natural gas production sold (1,574 bcf) was destined to Eni's Gas & Power segment.
In 2016, oil spills from operations reported a decrease of 13% compared to the previous year. The best improvement was reported in Nigeria due to the revamping of industrial installations.

Oil and natural gas production[a][b]

	Liquids (mmbbl)	Natural gas (bcf)	Hydrocarbons (mmboe)	Liquids (mmbbl)	Natural gas (bcf)	Hydrocarbons (mmboe)	Liquids (mmbbl)	Natural gas (bcf)	Hydrocarbons (mmboe)
Consolidated subsidiaries	**2014**			**2015**			**2016**		
Italy	27	213	65	25	200	62	17	172	49
Rest of Europe	34	195	69	31	201	68	40	184	73
North Africa	91	627	206	98	780	240	88	802	235
Sub-Saharan Africa	84	185	118	93	171	124	91	170	122
Kazakhstan	19	73	32	20	80	35	24	93	41
Rest of Asia	13	114	34	28	106	47	28	90	45
Americas	27	80	41	28	94	45	25	94	43
Australia and Oceania	2	40	10	2	41	9	1	42	8
	297	**1,527**	**575**	**325**	**1,673**	**630**	**314**	**1,647**	**616**
Equity-accounted entities									
North Africa	1	2	1	1	2	1	1	2	2
Sub-Saharan Africa		4	1					11	2
Rest of Asia		8	2	1	9	2	1	7	2
Americas	4		4	4	25	9	5	93	22
	5	**14**	**8**	**6**	**36**	**12**	**7**	**113**	**28**
Total	**302**	**1,541**	**583**	**331**	**1,709**	**642**	**321**	**1,760**	**644**

(a) Includes Eni's share of equity-accounted equities.
(b) Includes volumes of gas consumed in operations (32.1, 26.4 and 29.4 mmboe in 2016, 2015 and 2014, respectively).

(7) From January 1, 2016, as part of a regular reviewing procedure, Eni has updated the conversion rate of gas to 5,458 cubic feet of gas equals 1 barrel of oil (it was 5,492 cubic feet of gas per barrel in previous reporting periods). This update reflected changes in Eni's gas properties that took place in the last three years and was assessed by collecting data on the heating power of gas in all Eni's gas fields currently on stream. The effect of this update on production expressed in boe for the full year 2016 was 5 kboe/d. Other per-boe indicators were only marginally affected by the update (e.g. realization prices, costs per boe) and negligible was the impact on depletion charges. Other oil companies may use different conversion rates.

Oil and natural gas production[a][b]

	Liquids (kbbl/d)	Natural gas (mmcf/d)	Hydrocarbons (kboe/d)	Liquids (kbbl/d)	Natural gas (mmcf/d)	Hydrocarbons (kboe/d)	Liquids (kbbl/d)	Natural gas (mmcf/d)	Hydrocarbons (kboe/d)
Consolidated subsidiaries		**2014**			**2015**			**2016**	
Italy	**73**	**583.8**	**179**	**69**	**546.6**	**169**	**47**	**471.2**	**133**
Rest of Europe	**93**	**535.2**	**190**	**85**	**551.8**	**185**	**109**	**501.8**	**201**
Croatia		38.2	7		21.2	4		26.5	5
Norway	62	274.2	112	57	264.6	105	86	258.3	133
United Kingdom	31	222.8	71	28	266.0	76	23	217.0	63
North Africa	**248**	**1,718.9**	**562**	**268**	**2,138.0**	**658**	**241**	**2,192.2**	**643**
Algeria	83	141.3	109	79	94.1	96	77	115.5	98
Egypt	88	649.8	206	96	510.1	189	76	597.4	185
Libya	73	911.2	239	89	1,517.3	365	84	1,464.8	353
Tunisia	4	16.6	8	4	16.5	8	4	14.5	7
Sub-Saharan Africa	**231**	**507.5**	**323**	**256**	**468.3**	**341**	**247**	**464.3**	**333**
Angola	75	38.3	82	96	31.6	101	108	49.0	118
Congo	80	145.1	106	78	136.8	103	71	148.5	98
Nigeria	76	324.1	135	82	299.9	137	68	266.8	117
Kazakhstan	**52**	**200.7**	**88**	**56**	**218.3**	**95**	**65**	**254.0**	**111**
Rest of Asia	**36**	**310.4**	**93**	**77**	**289.8**	**130**	**78**	**245.8**	**123**
China	4		4	3		3	2		2
India		3.7	1		2.6	1			
Indonesia	1	52.6	11	2	54.8	12	3	48.5	12
Iran	1		1	22		22			
Iraq	21		21	40		40	64	19.2	67
Pakistan		248.2	45		226.4	41		172.1	32
Turkmenistan	9	5.9	10	10	6.0	11	9	6.0	10
Americas	**74**	**217.8**	**115**	**75**	**257.1**	**122**	**69**	**256.4**	**116**
Ecuador	12		12	11		11	10		10
Trinidad & Tobago		60.3	11		70.4	13		69.7	13
United States	62	157.5	92	64	186.7	98	59	186.7	93
Australia and Oceania	**6**	**110.5**	**26**	**5**	**111.8**	**26**	**3**	**113.9**	**24**
Australia	6	110.5	26	5	111.8	26	3	113.9	24
	813	**4184.8**	**1,576**	**891**	**4,581.7**	**1,726**	**859**	**4,499.6**	**1,684**
Equity-accounted entities									
Angola		10.3	2		0.9		1	29.1	6
Indonesia	1	23.2	5	1	24.1	5	1	18.8	4
Tunisia	4	5.3	5	4	5.2	4	3	4.9	4
Venezuela	10	0.8	10	12	68.9	25	14	254.8	61
	15	**39.6**	**22**	**17**	**99.1**	**34**	**19**	**307.6**	**75**
Total	**828**	**4,224.4**	**1,598**	**908**	**4,680.8**	**1,760**	**878**	**4,807.2**	**1,759**

(a) Includes Eni's share of equity-accounted equities.
(b) Includes volumes of gas consumed in operations (478, 397 and 442 mmcf/d in 2016, 2015 and 2014, respectively).

Productive wells

In 2016, oil and gas productive wells were 9,399 (3,737.6 of which represented Eni's share). In particular, oil productive wells were 6,673 (2,494.7 of which represented Eni's share); natural gas productive wells amounted to 2,726 (1,242.9 of which represented Eni's share).

The following table shows the number of productive wells in the year indicated by the Group and its equity-accounted entities in accordance with the requirements of FASB Extractive Activities oil&gas (Topic 932).

Productive oil and gas wells [a]

	2016			
	Oil wells		Natural gas wells	
(units)	Gross	Net	Gross	Net
Italy	243.0	197.1	616.0	532.4
Rest of Europe	395.0	72.5	160.0	88.1
North Africa	1,813.0	963.8	225.0	98.1
Sub-Saharan Africa	3,020.0	590.3	350.0	28.8
Kazakhstan	204.0	54.8		
Rest of Asia	727.0	479.1	1,036.0	393.2
Americas	264.0	133.3	321.0	98.5
Australia and Oceania	7.0	3.8	18.0	3.8
	6,673.0	**2,494.7**	**2,726.0**	**1,242.9**

(a) Includes 2,128 gross (741.9 net) multiple completion wells (more than one producing into the same well bore). Productive wells are producing wells and wells capable of production. One or more completions in the same bore hole are counted as one well.

Drilling

Exploration

In 2016, a total of 16 new exploratory wells were drilled (10.2 of which represented Eni's share), as compared to 29 exploratory wells drilled in 2015 (19.1 of which represented Eni's share) and 44 exploratory wells drilled in 2014 (25.8 of which represented Eni's share).

The following tables show the number of net productive, dry and in progress exploratory wells in the years indicated by the Group and its equity-accounted entities in accordance with the requirements of FASB Extractive Activities-oil&gas (Topic 932).

The overall commercial success rate was 50% (50% net to Eni) as compared to 16.7% (25.1% net to Eni) in 2015 and 31.3% (38.0% net to Eni) in 2014.

Exploratory Well Activity

	Net wells completed [a]				Wells in progress at Dec. 31 [b]			
	2014		2015		2016		2016	
(units)	Productive	Dry [c]	Productive	Dry [c]	Productive	Dry [c]	Gross	Net
Italy		0.6				1.0	4.0	2.3
Rest of Europe		4.3		2.2	0.1	0.4	9.0	2.3
North Africa	3.5	4.3	3.3	5.8	6.0	1.8	16.0	12.3
Sub-Saharan Africa	7.3	7.3	0.6	2.9	0.1	1.1	32.0	17.0
Kazakhstan							6.0	1.1
Rest of Asia	1.3	4.3		3.4		0.9	8.0	3.2
Americas	2.0	1.4	1.0	0.3		1.0	3.0	1.5
Australia and Oceania		0.9					1.0	0.3
	14.1	**23.1**	**4.9**	**14.6**	**6.2**	**6.2**	**79.0**	**40.0**

(a) Includes number of wells in Eni's share.
(b) Includes temporary suspended wells pending further evaluation.
(c) A dry well is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas sufficient quantities to justify completion as an oil or gas well.

Development

In 2016, a total of 296 development wells were drilled (118.7 of which represented Eni's share) as compared to 335 development wells drilled in 2015 (132.4 of which represented Eni's share) and 440 development wells drilled in 2014 (191 of which represented Eni's share).

The drilling of 68 development wells (28.6 of which represented Eni's share) is currently underway.

The following tables show the number of net productive, dry and in progress development wells in the years indicated by the Group and its equity-accounted entities in accordance with the requirements of FASB Extractive Activities - oil&gas (Topic 932).

Development Well Activity

	Net wells completed[a]						Wells in progress at Dec. 31	
	2014		2015		2016		2016	
(units)	Productive	Dry[b]	Productive	Dry[b]	productive	Dry[b]	Total	Net
Italy	12.5		6.0		4.0		1.0	1.0
Rest of Europe	9.8	1.0	10.2	0.1	5.6		4.0	0.6
North Africa	54.5	1.0	30.5	2.8	38.6	1.2	18.0	10.0
Sub-Saharan Africa	31.6		22.0	2.5	21.2	0.2	36.0	14.0
Kazakhstan	1.5		4.7		4.6		3.0	0.8
Rest of Asia	54.2	1.6	29.7	5.9	31.6	0.5	2.0	0.3
Americas	22.1	0.7	17.4	0.1	9.9	1.3	4.0	1.9
Australia and Oceania	0.1	0.4	0.5					
	186.3	**4.7**	**121.0**	**11.4**	**115.5**	**3.2**	**68.0**	**28.6**

(a) Includes number of wells in Eni's share.
(b) A dry well is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas sufficient quantities to justify completion as an oil or gas well.

Acreage

In 2016, Eni performed its operations in 44 countries located in five continents. As of December 31, 2016, Eni's mineral right portfolio consisted of 780 exclusive or shared rights of exploration and development activities for a total acreage of 323,896 square kilometers net to Eni (342,708 square kilometers net to Eni, at December 31, 2015) of which developed acreage of 32,489 square kilometers and undeveloped acreage of 291,407 square kilometers net to Eni. In 2016, changes in total net acreage mainly derived from: (i) new leases mainly in Egypt, Ghana, Morocco, Montenegro, Norway and the United Kingdom for a total acreage of approximately 10,500 square kilometers; (ii) the total relinquishment of licenses mainly in Australia, Gabon, India, Liberia, Norway and the United States covering an acreage of approximately 13,000 square kilometers; and (iii) partial relinquishment in Australia, Portugal and South Africa or interest reduction mainly in Myanmar, for approximately 17,000 square kilometers.

Oil and natural gas interests

	December 31, 2015	December 31, 2016						
	Total net average[a]	Number of interest	Gross developed acreage[a][b]	Gross undeveloped acreage[a]	Total gross acreage[a]	Net developed acreage[a][b]	Net undeveloped acreage[a]	Total net acreage[a]
EUROPE	**45,123**	**295**	**15,693**	**51,758**	**67,451**	**10,827**	**34,553**	**45,380**
Italy	**16,975**	**146**	**10,498**	**10,320**	**20,818**	**8,775**	**7,992**	**16,767**
Rest of Europe	**28,148**	**149**	**5,195**	**41,438**	**46,633**	**2,052**	**26,561**	**28,613**
Cyprus	10,018	3		12,523	12,523		10,018	10,018
Croatia	987	2	1,975		1,975	987		987
Greenland	1,909	2		4,890	4,890		1,909	1,909
Montenegro		4		1,228	1,228		614	614
Norway	3,114	57	2,311	6,045	8,356	452	2,156	2,608
Portugal	6,370	3		4,547	4,547		3,182	3,182
United Kingdom	1,905	67	909	5,932	6,841	613	5,715	6,328
Other Countries	3,845	11		6,273	6,273		2,967	2,967
AFRICA	**157,441**	**264**	**46,384**	**264,600**	**310,984**	**11,729**	**140,947**	**152,676**
North Africa	**25,699**	**121**	**14,292**	**54,122**	**68,414**	**5,738**	**23,654**	**29,392**
Algeria	1,179	42	3,222	187	3,409	1,148	31	1,179
Egypt	9,668	57	5,508	22,523	28,031	2,074	8,591	10,665
Libya	13,294	11	1,962	24,673	26,635	958	12,336	13,294
Morocco		1		6,739	6,739		2,696	2,696
Tunisia	1,558	10	3,600		3,600	1,558		1,558
Sub-Saharan Africa	**131,742**	**143**	**32,092**	**210,478**	**242,570**	**5,991**	**117,293**	**123,284**
Angola	4,404	57	8,160	12,892	21,052	1,024	3,343	4,367
Congo	1,354	25	1,794	657	2,451	971	197	1,168
Gabon	7,615	4		6,217	6,217		6,217	6,217
Ghana	100	3		1,353	1,353		579	579
Ivory Coast	429	1		954	954		286	286
Kenya	40,426	7		61,363	61,363		41,173	41,173
Liberia	1,841	1		2,341	2,341		585	585
Mozambique	1,956	6		3,911	3,911		1,956	1,956
Nigeria	7,432	34	22,138	8,631	30,769	3,996	3,374	7,370
South Africa	32,881	1		65,696	65,696		26,279	26,279
Other Countries	33,304	4		46,463	46,463		33,304	33,304
ASIA	**117,183**	**59**	**18,165**	**198,024**	**216,189**	**6,016**	**103,745**	**109,761**
Kazakhstan	**869**	**6**	**2,391**	**2,542**	**4,933**	**442**	**427**	**869**
Rest of Asia	**116,314**	**53**	**15,774**	**195,482**	**211,256**	**5,574**	**103,318**	**108,892**
China	7,069	8	77	7,056	7,133	13	7,056	7,069
India	6,167	1		13,110	13,110		5,244	5,244
Indonesia	25,124	14	4,246	30,243	34,489	1,603	23,578	25,181
Iraq	446	1	1,074		1,074	446		446
Myanmar	20,050	4		24,080	24,080		13,558	13,558
Pakistan	8,810	14	10,177	11,486	21,663	3,332	5,414	8,746
Russia	20,862	3		62,592	62,592		20,862	20,862
Timor Leste	1,230	1		1,538	1,538		1,230	1,230
Turkmenistan	180	1	200		200	180		180
Vietnam	23,132	5		30,777	30,777		23,132	23,132
Other Countries	3,244	1		14,600	14,600		3,244	3,244
AMERICAS	**6,628**	**148**	**4,948**	**8,154**	**13,102**	**3,208**	**2,488**	**5,696**
Ecuador	1,985	1	1,985		1,985	1,985		1,985
Mexico	67	3		67	67		67	67
Trinidad & Tobago	66	1	382		382	66		66
United States	2,118	129	1,320	997	2,317	660	526	1,186
Venezuela	1,066	6	1,261	1,543	2,804	497	569	1,066
Other Countries	1,326	8		5,547	5,547		1,326	1,326
AUSTRALIA AND OCEANIA	**16,333**	**14**	**1,140**	**15,728**	**16,868**	**709**	**9,674**	**10,383**
Australia	16,333	14	1,140	15,728	16,868	709	9,674	10,383
Total	**342,708**	**780**	**86,330**	**538,264**	**624,594**	**32,489**	**291,407**	**323,896**

(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.

Main exploration and development projects

Italy

On August 12, 2016 the activity of the Val d'Agri Oil Centre (Eni's interest 60.77%) in Viggiano gradually restarted following notification by the Italian Public Prosecutor of Potenza that has definitively repealed the plant seizure and by the National Mining Office for Hydrocarbons and Earth Resources of the Ministry of Economic Development that has authorized the plant's operation. The resumption of production is a result of the completion in June 2016 of certain plant upgrading, which do not alter the plant set up, authorized by the in-charge department of the Italian Ministry of Economic Development in order to address the alleged environmental crimes issued by the public prosecutor.
The development plan is progressing in line with the commitments agreed with the Basilicata Region, particularly in 2016: (i) the Environmental Monitoring Plan is being implemented. This project represents a benchmark in terms of environmental protection; and (ii) programs to support culture, enhancement of agricultural activities and socio-economic development in the area are in progress.
Development activities in the Adriatic offshore concerned: (i) maintenance and production optimization, mainly at the Barbara, Cervia/Arianna and Morena fields; and (ii) start-up of the Clara NW development project.
Following the Memorandum of Understanding for the Gela area, signed with the Ministry of Economic Development in November 2014, the Argo and Cassiopea offshore development project progressed. The project was submitted to the relevant Authorities and planned an optimization activities aiming to reduce environmental impact, to improve local economic and employment development and to recover areas of Eni's refinery already reclaimed for the construction of treatment plants. This program is subject to the authorization of the relevant Authorities. In addition, the Memorandum includes certain Eni's projects to support sustainable development in the area with an overall expense of €32 million. Three implementing agreements were signed: one of them was already completed and concerned the construction of an exhibition hall at the Gela Archaeological Museum. Others defined activities concerned projects to support young entrepreneurs and to upgrade and enhance the Gela harbor.

Rest of Europe

Norway Exploration activities yielded positive results at the beginning of 2017 with a new oil and gas discovery in the PL 128/128D license (Eni's interest 11.5%), nearby the production facilities of the Norne field (Eni's interest 6.9%). This new discovery is in line with Eni's exploration strategy of focusing on near-field incremental activities for a fast-track development.
In 2016, Eni was awarded the following exploration licenses: (i) PL 128D (Eni's interest 11.5%) in the Norwegian Sea; (ii) PL 816 (Eni operator with a 70% interest) in the Norwegian section of the North Sea; and (iii) PL 229D (Eni operator with a 65% interest) and PL 849 (Eni's interest 30%) in the Barents Sea.
In January 2017, Eni was awarded further exploration licenses: (i) PL 128E (Eni's interest 11.5%) in the Norwegian Sea; and (ii) PL 900 (Eni operator with a 90% interest) and PL 901 (Eni's interest 30%) in the Barents Sea.
In March 2016, production start-up was achieved at the Goliat field (Eni operator with a 65% interest) in the Barents Sea. Field production reached the target of 100 kboe/d (65 kboe/d net to Eni) and during the year peak production of approximately 114 kboe/d (approximately 74 kboe/d net to Eni) was achieved. The field is estimated to contain reserves amounting to approximately 180 mmbbl. The project includes a subsea system consisting of 22 wells linked to the largest cylindrical FPSO in the world by subsea production and injection flowlines. The use of well-advanced technologies, electricity supply provided to the platform from the mainland and the re-injection of produced water and natural gas into reservoir as well as zero gas flaring during production activities allow to minimize environmental impact.
Other main activities concerned: (i) the drilling of infilling wells to support production at the Ekofisk and Eldfisk fields in the PL 018 (Eni's interest 12.39%) in the Norwegian section of the North Sea; and (ii) maintenance and optimization of production, mainly at the Asgard (Eni's interest 14.82%), Heidrun (Eni's interest 5.17%) and Norne Outside (Eni's interest 11.5%) fields in the Norwegian Sea.

United Kingdom In 2016, Eni was awarded the operatorship and a 100% interest in the PL2287, PL2288 and PL2292 exploration licenses in the Irish Sea and the Liverpool Bay Area, nearby operated production assets.
The Phase 2 development activities of West Franklin field (Eni's interest 21.87%) was completed and during the year peak production of 61 kboe/d (13 kboe/d net to Eni) was achieved.

North Africa

Algeria In 2016, Eni signed with the relevant Authorities an unitisation agreement of the SF-SFNE fields and a 10-year extension of the fields in the Blocks 401a/402a (Eni's interest 55%).
Production start-up was achieved at the CAFC oil project in the Block 405b (Eni's interest 75%) at the end of the year, with start-up of 6 wells and linkage at the existing treatment facilities of the MLE project. The development activities are expected to be completed during 2017.
Development and optimization activities progressed at the MLE and CAFC gas fields by means of construction and infilling activities, as well as production optimization.
Other development activities concerned infilling activities and production optimization at the Rod field (Eni operator with a 66% interest), also by means of the application of the Enhanced Oil Recovery WAG (Water Alternate Gas injection) technology.

Egypt In December 2016, Concession Agreements were ratified for the North El Hammad (Eni operator with a 37.5% interest) and North Ras El Esh (Eni's interest 50%) blocks, located in the conventional offshore of the Mediterranean Sea.
In February 2016, the Egyptian Ministry of Petroleum and Mineral Resources approved the award to Eni the Zohr Development Lease that allows the start-up of the development program at the Zohr gas field in the Shorouk operated license (Eni's interest 100%) and, as a consequence, the FID was sanctioned and added proved

reserves for the field. The first gas is expected at the end of 2017. Eni successfully performed the first production test of two wells and drilling delineation and development activities confirming the mineral potential of discovery at approximately 30 Tcf of gas in place. Drilling activities will continue in 2017 together with construction activities of onshore gas treatment plant and offshore facilities installation.
Eni signed two agreements with major international players in the oil&gas business for the disposal of a 40% interest in the giant discovery Zohr. These transactions are a part of Eni's "dual exploration model" which is targeting simultaneously the fast-track development of discovered resources and the partial dilution of the high stakes retained in exploration leases to monetize in advance part of discovered volumes. The agreements concerned the sale of: (i) a 10% interest to BP for a consideration amount of $375 million and the pro-quota reimbursement of past expenditures, which amount so far at approximately $150 million; and (ii) a 30% interest to Rosneft for a consideration amount of $1,125 million and the pro-quota reimbursement of past expenditures, which amount so far at approximately $450 million. In addition, the new partners have an option to buy a further 5% interest under the same terms.
In February 2017, Eni signed a deed completing the sale of 10% interest to BP, with all authorizations from Egypt's authorities. The sale agreement with Rosneft will be finalized in the first half of 2017 and subject to necessary authorizations from Country's authorities.
During the year, targeting production of 85.5 kboe/d net to Eni was achieved at the Nidoco NW field and satellites as a part of the Great Nooros Area project in the Abu Madi West concession (Eni's interest 75%). The start-up was achieved in 13 months following the announcement of the commercial discovery in July 2015 by means of the exploration successes in the Nooros area and the drilling of the new development wells. Production plateau of 160 kboe/d is expected in 2017 with the completion of ongoing development activities.
The potential at the Baltim South West field discovery (Eni operator with a 50% interest), in the conventional offshore, was upped to approximately 1 Tcf of gas in place due to successful test of the delineation well. The discovery is located near the Great Nooros Area.
Other development activities concerned: (i) ongoing activity of the sub-sea END Phase 3 development project in the Ras El Barr concession (Eni's interest 50%) with the drilling and completion of two wells; (ii) infilling activities and production optimization at the Sinai 12 (Eni's interest 100%), Ashrafi (Eni's interest 25%) and Meleiha (Eni's interest 76%) concessions to support production capacity; (iii) start-up of the onshore gas treatment plant in the Meleiha concession.
In 2016, Eni started promoting initiatives to support socio-economic development and health of local communities, in particular in the Port Said area. Eni defined a first health program in the Al Garabaa area, west of Port Said, according to Ministry of Petroleum and Ministry of Health. The program includes activities to improve and strengthen emergency services and primary health care.

Libya Development activities concerned: (i) planned facilities downtime at the Mellitah treatment plant, the Sabratha production platform and the Wafa treatment facilities of the Western Libyan Gas Project (Eni's interest 50%); (ii) positioning and installation activities as well as linkage of the new FSO unit at the Bouri production field (Eni's interest 50%) and start-up at the beginning of 2017; (iii) a second development phase of the Bahr Essalam field (Eni's interest 50%) with the completion of 10 offshore wells of which 9 wells already drilled in 2016. The EPCI contract was awarded to supply and installation of flowlines. First gas is expected in 2018; and (iv) the linkage of one additional production wells at the Wafa field (Eni's interest 50%) and activities in order to mitigate the natural production decline in the area.

Sub-Saharan Africa

Angola Eni started production in the Block 15/06 (Eni operator with a 36.84% interest) at the end of 2014 with the West Hub Development Project that represents the first Eni-operated producing project in the Country. The development program plans to hook up the Block's discoveries to the N'Goma FPSO in order to support production plateau. In 2016, production started up at the M'Pungi and M'Pungi North fields and the related production ramp-up allowed to achieve an overall production of approximately 81 kbbl/d (approximately 28 kbbl/d net to Eni). According to the project further 5 fields will be put into production with completion expected in 2019. The development plan includes water and gas injection wells in line with the zero flaring policy.
In February 2017, production start-up was achieved at the East Hub project, five months earlier than scheduled and with a time-to-market among the best in the industry, by means of the linkage of Cabaça South East field to the FPSO Armada Olombendo. In the Block 15/06, with the completion of the East Hub project, production derived from five fields. Management plans to put into production two additions discoveries by the end of 2018.
Early production phase started up at the Mafumeira Sul project in the Block 0 (Eni's interest 9.8%). Development activities progressed, with the completion expected during 2017 and a peak production of 100 kboe/d.
During the year, Eni signed the Malembo Gas Supply Agreement with the national oil company Sonagas to supply associated gas deriving from production of the Block 0 to the power plant in the Malongo area.
Other development activities concerned: (i) the completion of the Congo River Crossing project to supply gas production of Block 0 and 14 (Eni's interest 20%) to Angola LNG liquefaction plant (Eni's interest 13.6%) which started up in April 2016 with an average production of 6 kboe/d net to Eni; and (ii) development program of the Kizomba satellites Phase 2 (Eni's interest 20%) which will be started up leveraging on the production and treatment facilities in the area.

Congo In December 2016, production ramp-up was achieved at the Nené Marine field, in the Marine XII block (Eni operator with a 65% interest) with the completion of the second development phase, sanctioned in 2015.
Development activities progressed at the Litchendjili production field in the Marine XII block and during the year the peak production of approximately 16 kboe/d was achieved. Gas production feeds the CEC power plant (Eni's interest 20%).
The Project Integreé Hinda (PIH) was completed in the year. The project provided to support 22 local communities in the M'Boundi area and involved approximately 25,000 people. In the 2010-2016 period, this program provided to improve primary education, access to water, maternal and child health as well as the construction of

training center for the development of farming. Additional ongoing projects include the construction of facilities to support the enhancement of local culture with restructuring and rehabilitation initiatives in the Brazzaville, Pointe Noire and Makoua area.
In December 2016, Eni signed a framework agreement with the Republic of the Congo aimed at integrated development and monetization of gas produced in the Country, in line with three strategic guidelines of access to energy, of local development and of zero flaring in the development programs of oil and gas discoveries.

Ghana In March 2016, Eni was awarded the operatorship of the Cape Three Points Block 4 exploration license (Eni's interest 42.47%) in the offshore of the Country. The new block covers an area of approximately 1,000 square kilometers in water depths ranging from 100 to 1,200 meters and is located near the operated OCTP block (Eni's interest 44.44%). In case of exploration success, the block will benefit from the OCTP project infrastructures, under development.
Development activities concerned the OCTP integrated oil&gas development plan. First oil is expected in 2017 and first gas in 2018. In 2016, the drilling activity of 18 development wells was completed and the renovation of a FPSO unit was performed. Contracts were awarded for the installation of sea-lines and the construction of onshore gas plant. The OCTP project will be developed in compliance with the highest environmental requirements defined in the Performance Standards on Environmental and Social Sustainability of the International Finance Corporation (IFC), which is part of the World Bank Group. The use of the most advanced technologies, the re-injection of produced water as well as zero gas flaring during production activities will allow to minimize environmental impact. Furthermore, the non-associated gas, which will be produced, will be used in existing power plants and in the future will feed new plants.
The Livelihood Restoration Plan started in the year. The project will support local communities nearby the OCTP development program during the 2016-2020 period. The target is to sustainably restore and improve living conditions of affected households through project options appropriate to the socio-economic context. The program provides initiatives in agriculture, livestock breeding, fishing and micro-entrepreneurship.
The sustainability project in the Sanzule area was completed in 2016 with the construction and rehabilitation of health facilities and the training of local health workers.

Mozambique In March 2017, ExxonMobil and Eni signed sale and purchase agreement to acquire a 25% indirect interest in the Area 4 block, offshore Mozambique. Eni currently holds a 50% indirect interest in the block through a 71.4% stake in Eni East Africa, which is operator of the Area 4 concession with a 70% interest. The agreed terms include a cash price of approximately $2.8 billion. The acquisition will be completed subject to satisfaction of certain conditions precedent, including clearance from Mozambican and other regulatory authorities. Following completion of the transaction, Eni East Africa will be co-owned by Eni and ExxonMobil with a 35.7% stake and the remaining interest of 28.6% by CNPC. Eni will continue to lead the Coral Floating LNG project and all upstream operations in Area 4, while ExxonMobil will lead the construction and operation of natural gas liquefaction facilities onshore. This operating model will enable the use of best practices and skills within Eni and ExxonMobil with each company focusing on distinct and clearly defined scopes while preserving the benefits of a fully integrated project.
The Coral South Development Plan, which was approved by the Government of Mozambique in February 2016, envisages the installation of a floating unit for the treatment, liquefaction and storage of natural gas (Floating LNG - FLNG) with a capacity of over 3.3 mmtonnes/y fed by 6 subsea wells. Eni expects to produce up to 5 TCF of gas with a start-up expected in mid-2022. In October 2016, Eni and its Area 4 partners signed a binding agreement with BP for the sale of the entire volumes of LNG produced by the Coral South Project, for a period of over twenty years. In November 2016, Eni's Board of Directors approved the investment for the first development phase of the Coral discovery. The FID on the project will turn effective once all Area 4 partners sanctioned it and the project financing, which is currently being finalized, will be underwritten.
The development plan of the Mamba comprises the construction of two onshore LNG trains with a combined capacity of 10 mmtonnes/y and the drilling of 16 subsea wells, with start-up in 2023. Eni expects to produce up to 14 TcF of gas according to its independent industrial plan, coordinated with the operator of Area 1 (Anadarko). The FID is expected in 2018.
Leveraging on Eni's cooperation model, a medium-long-term program was defined to support local communities also involving all local stakeholders as integrated part of the development activity. The guidelines of the program include projects to develop the socio-economic conditions of local communities and respect for biodiversity. In particular, during 2016, certain projects were completed, such as: (i) initiatives in the primary education in the Pemba area with professional and non-formal training programs and supply of school equipment and stuff; (ii) the renovation of the connecting road to the fish market in the Palma area; and (iii) specific training initiatives dedicated to doctors, nurses and hospital technicians.

Nigeria On January 27, 2017, Eni's subsidiary Nigerian Agip Exploration Ltd became aware of an Interim Order of Attachment ("Order") issued by the Nigerian Federal High Court, sitting in Abuja, upon request from the Economic and Financial Crime Commission (EFCC), attaching the property OPL 245, pending the Nigerian proceeding. Both Eni and Shell made a prompt application to discharge the Order. On March 17, 2017, the Nigerian Court discharged the Order. On that basis, management has concluded that no impairment of the asset was required. After the inception of the judicial proceeding in Italy, which dates back to July 2014, Eni's Board of Statutory Auditors jointly with the Eni Watch Structure has engaged a US leading law firm to perform an independent review of the issue. Based on the outcome of this review, during which the law firm appointed by Eni has also assessed material and the information made available from the judicial authorities, no wrongdoing has been detected on Eni side in the awarding process to Eni of the license. For further information see also Notes no. 16 "Property, Plant and Equipment" and no. 38 "Guarantees, commitments and risks" to Consolidated Financial Statements of the Annual report on Form 20-F 2016.
In January 2017, Eni signed a Memorandum of Understanding with the Nigerian National Petroleum Corporation (NNPC) to promote new activities that can significantly boost Nigeria's social and economic development. In particular, the cooperation agreement

includes: (i) an increased focus on development and exploration activities in the onshore, offshore and ultra-deep-water areas; (ii) cooperation requirements for the rehabilitation and enhancement of Port Harcourt refinery; (iii) the fast track development of the Okpai combined cycle power plant by means of doubling the power generation capacity; and (iv) the assessment of additional projects to secure energy accessibility to the Country's most remote areas.
The development activities concerned: (i) drilling activity and production start-up of three additional wells, two production and one water-injection, at the Bonga field in the OML 118 block (Eni's interest 12.5%); (ii) the drilling campaign within the integrated project in the Gbaran-Ubie area in the OML 28 block (Eni's interest 5%), aimed to supply natural gas to the Bonny liquefaction plant. Start-up was achieved in the second half of 2016; and (iii) the OML 43 block (Eni's interest 5%), where the development plan of the Forcados-Yokri field provides the hook-up the last 12 out of 23 production wells already drilled, the upgrading of existing flowstations and the construction of transport facilities. Start-up is expected in the first half of 2017.
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 is operational, with a treatment capacity of approximately 1,236 bcf/y of feed gas corresponding to a production of 22 mmtonnes/y of LNG on six trains. Natural gas supplies to the plant are currently provided under gas supply agreements from the SPDC JV and the NAOC JV, the latter operating the OMLs 60, 61, 62 and 63 blocks (Eni's interest 20%) with an average amount of approximately 2,825 mmcf/d for the next four years (approximately 265 mmcf/d net to Eni corresponding to approximately 49 kboe/d). 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 Co.
In 2016, programs progressed to support the local community in the Niger Delta, with initiatives in the public infrastructure, primary education services, health and access to energy programs as well as training programs to promote the socio-economic development, in particular in the agricultural sector.
In November 2016, the twentieth edition of the Farmer Day of the Green River Project was held. The Green River Project, which was launched in 1987, supports the development and sustainable management of farms and processing centers of agricultural products. The project directly involved 35,000 farmers, benefiting 500,000 people in 120 communities.

Kazakhstan

Kashagan On September 28, 2016, production re-started at the Kashagan field (Eni's interest 16.81%) with the completion of works to fully replace the damaged pipelines following the gas leak occurred at the end of 2013. The production of 185 kboe/d was achieved by year-end. The production capacity of 370 kbbl/d planned for the Phase 1 is expected to be achieved during 2017, when gas reinjection comes online.
Within the agreements with local Authorities, Eni has been conducting training program for Kazakh resources in the oil&gas sector, in addition to the realization of infrastructures with social purpose.
As of December 31, 2016, the aggregate costs incurred by Eni for the Kashagan project capitalized in the financial statements amounted to $9.7 billion (€9.2 billion at the EUR/USD exchange rate of December 31, 2016). This capitalized amount included: (i) $7.2 billion relating to expenditure incurred by Eni for the development of the oil field; and (ii) $2.5 billion relating primarily to accrue finance charges and expenditures for the acquisition of interests in the Consortium from exiting partners upon exercise of pre-emption rights in previous years.
As of December 31, 2016, Eni's proved reserves booked for the Kashagan field amounted to 608 mmboe, barely unchanged from 2015.

Karachaganak The Expansion Project of the Karachaganak field (Eni's interest 29.25%) is currently under study. The project targets to install, in stages, the gas treatment plants and re-injection facilities to support liquids' production profile. The development plan is currently in the phase of technical and marketing definition of its first development phase, aimed to increase the capacity of gas re-injection.
Eni continues its commitment to support local communities in the nearby area of Karachaganak field. In particular, activities focused on: (i) the professional training; and (ii) the construction of kindergartens, maintenance of hospitals and roads, building of heating plants and sport centres.
Moreover, following the re-definition of the Sanitary Protection Zone (SPZ) associated to the ongoing development projects and in according to the international standards and best practices, a project of relocation of the inhabitants from Berezovka and Bestau villages progressed. In 2016, the first phase of the project, which started in 2015, was completed with the relocation of part of the population, the construction of schools and roads and interventions to ensure the supply of gas and water. The activities progressed to relocate the remaining population and are expected to be completed in 2017.
Eni continues to conduct monitoring activities on biodiversity and ecosystems in the nearby of the production areas.
As of December 31, 2016, Eni's proved reserves booked for the Karachaganak field amounted to 613 mmboe, reporting an increase of 26 mmboe from 2015 mainly due to lower marker Brent price.

Rest of Asia

Indonesia Exploration activities yielded positive results with the Merakes 2 appraisal well confirming the mineral potential of the Merakes gas discovery in the western area of the East Sepinggan block (Eni operator with an 85% interest). The discovery, nearby the Jangkrik project (Eni operator with a 55% interest), will leverage on the synergies with existing facilities to reduce costs and time of the execution of the future subsea development and confirms the success of Eni's near field exploration and appraisal strategy.
In 2016, production start-up was achieved at the Bangka project (Eni's interest 20%) in the East Kalimantan.
The ongoing development activities that will ensure gas supplies to the Bontang liquefaction plant include the Jangkrik project in the Kalimantan offshore. This project is in the final execution phase with all the deep-offshore development subsea wells already drilled and the Floating Production Unit for gas and condensate treatment in the final stage of construction, as well as the construction of

transportation and receiving facilities onshore. Production start-up is planned in 2017.
Ongoing initiatives progressed in the field of environmental protection, health care and educational system to support local communities located in the operated areas of the eastern Kalimantan, Papua and North Sumatra.

Iraq At the beginning of March 2016, three new generation plants for the oil, gas and water treatment (Initial Production Facilities – IPF) started. Those plants together with existing restructured and modernized facilities increased oil and natural gas treatment capacity of Zubair field (Eni's interest 41.6%) to approximately 650 kbbl/d and will ensure the maximization of the associated gas utilization. In addition, these new facilities have also a water re-injection capacity of approximately 300 kbbl/d that will boost the Zubair's hydrocarbons production and will achieve production plateau.
The first stage of development activities (Rehabilitation Plan) of Zubair field was completed with the start-up of these new facilities.
Ongoing development activities concerned an additional development phase (Enhanced Redevelopment Plan) of the Zubair field, to achieve a production plateau of 700 kbbl/d and will ensure the application of associated gas to power generation.
Supporting programs for the local community progressed with main activities related to infrastructural projects aimed at strengthening basic services, to support teaching activities, renovation of school buildings and access to water as well as sanitation programs and roads construction. In addition, in 2016, a primary school was opened in the Al Barjazia area.

Americas

United States During the year, production start-ups were achieved in the Gulf of Mexico at: (i) the Heidelberg project (Eni's interest 12.5%) in the deep-water Gulf of Mexico, with a production of approximately 3 kboe/d net to Eni. During 2017 planned development activities will be completed; (ii) the Phase 2 development of Lucius field (Eni's interest 8.5%) with production ramp-up to 100 kboe/d (8 kboe/d net to Eni); and (iii) the Devil's Tower South-West production well within the development program of the operated Devil's Tower field (Eni's interest 75%), with a production of approximately 2 kboe/d.

Venezuela Development activities concerned: (i) ongoing drilling activities at the Junin 5 oil field (Eni's interest 40%), located in the Orinoco Oil Belt. Possible optimization of development program is currently under evaluation; and (ii) the completion of the first development phases at the giant Perla gas field in the Cardon IV block (Eni's interest 50%). The Perla project includes two additional development phases to achieve a production plateau of approximately 1,200 mmcf/d.
In 2016, certain wind farms were built to supply electricity to the Punta Macolla area.

Capital expenditure

Capital expenditure of the Exploration & Production segment (€8,254 million) concerned development of oil and gas reserves (€7,770 million) directed mainly outside Italy, in particular in Egypt, Angola, Kazakhstan, Indonesia, Iraq, Ghana and Norway.
Development expenditures in Italy concerned in particular the facility upgrading of Viggiano oil center in Val d'Agri (see - Main exploration and development projects - Italy) as well as sidetrack and workover activities in mature fields.
Exploration expenditures (€417 million) were directed in particular to Egypt, Indonesia, Libya and Angola.
In 2016 overall expenditure in R&D of the E&P segment amounted to €62 million (€78 million in 2015).

Capital expenditure (€ million)	2014	2015	2016	Change	% Ch.
Acquisition of proved and unproved properties			**2**	**2**	..
North Africa			2		
Exploration	**1,030**	**566**	**417**	**(149)**	**(26.3)**
Italy	1				
Rest of Europe	132	133	11		
North Africa	177	232	312		
Sub-Saharan Africa	511	157	30		
Rest of Asia	89	15	57		
Americas	109	29	7		
Australia and Oceania	11				
Development	**9,021**	**9,341**	**7,770**	**(1,571)**	**(16.8)**
Italy	880	679	407		
Rest of Europe	1,574	1,264	590		
North Africa	832	1,570	2,447		
Sub-Saharan Africa	3,085	2,998	2,176		
Kazakhstan	521	835	707		
Rest of Asia	1,105	1,333	1,213		
Americas	921	637	220		
Australia and Oceania	103	25	10		
Other expenditure	**105**	**73**	**65**	**(8)**	**(11.0)**
	10,156	**9,980**	**8,254**	**(1,726)**	**(17.3)**