Exploration & Production

Adjusted operating profit
(€ million)

Oil spills due to operations
(bbl;>1 bbl)

Emissions from flaring
(mmtonnes CO_2eq)

Hydrocarbons production
(kboe/d)

Injury frequency rate
(No. of accidents per million of worked hours)

Proved hydrocarbons reserves
(mmboe)

900 mmboe
resources discovered in the year

100,000 sqkm
exploration acreage acquired

112%
reserves replacement ratio, all sources

€10.5 billion
capital expenditures in reserves exploration and development

56%
record level of produced water re-injected

+0.6% production
in the year, excluding the impact of assets in Siberia

Performance of the year

In 2014, the injury frequency rate confirmed the positive performance reported in 2013.

Greenhouse gas emissions decreased by 11.3% compared to the previous year (with a 33.5% reduction in emissions from flaring) mainly due to the conclusion of the flaring down project at M'Boundi field in Congo and the ramp-up of relevant projects in Nigeria;

Oil spills reported a decline from 2013 (with a 46% decrease in oil spills due to operations), while zero blow-outs were recorded for the eleventh consecutive year;

Continued a positive trend in increasing water reinjection, with a record level of 56%, due among other to the completion of relevant projects, in particular in Nigeria, Egypt, Indonesia and Turkmenistan;

In 2014 the E&P segment reported a decline of €1,527 million or 25.7% in adjusted net profit compared to a year ago, due to lower crude oil and gas prices in dollar terms (down by 8.9% on average) reflecting the fall of Brent crude benchmark and the weakness of gas market, especially in Europe;

Oil and natural gas production was 1.598 million boe/d in 2014 (up by 0.6% compared to the previous year), excluding the impact of the divestment of Eni's interest in Siberian assets;

Estimated net proved reserves at December 31, 2014 amounted to 6.6 bboe based on a reference Brent price of $101 per barrel. The reserves replacement ratio was 112%. The reserves life index was 11.3 years (11.1 years in 2013).

Exploration activity

Eni continued its track record of exploratory success. Additions to the Company's reserve backlog were approximately 900 million boe of resources for the full year, at a competitive cost of $2.1 per barrel. Near-field discoveries marked the year's activity:

The Ochigufu 1 NFW well located in the Angolan deep waters of Block 15/06 (Eni operator with a 35% interest). This discovery with a potential in place estimated at approximately 300 million barrels of oil, is located near the West Hub project, which started up at the end of 2014;

> The Minsala Marine 1 NFW in the conventional waters of block Marine XII (Eni operator with a 65% interest) in Congo, was the third discovery in the last two years increasing the block's resources in place by 1 billion barrels with characteristics similar to the previous discoveries of Litchendjili and Nené, the latter started up early production in record time;

> The Oglan-2 exploration well in Block 10 (Eni operator with a 100% interest), in Ecuador, with a potential in place estimated at approximately 300 million barrels of oil. The discovery is located near the processing facilities of the operated field of Villano and will be put in production with fast-track development;

> The Merakes 1 NFW gas well in East Sepinggan offshore block (Eni operator with a 85% interest), in Indonesia. This discovery with a potential in place estimated at approximately 1.3 Tcf, is located in proximity of the operated field of Jangkrik (Eni's interest 55%), which is currently under development and will supply additional gas volumes to the Bontang LNG plant;

> The conventional waters of Gabon, the Nyonie Deep 1 well in the Block D4 (Eni operator with a 100% interest) showed an estimated potential of approximately 500 million boe in place of gas and condensates;

> The appraisal gas wells Agulha 2 and Coral 4 DIR, confirming the extension of their respective fields with a potential in place in Area 4 (Eni operator with a 50% interest) estimated at approximately 88 Tcf;

> The exploration portfolio was strengthened by means of new exploration acreage covering approximately 100,000 square kilometres net to Eni in the high potential areas such as Myanmar, Portugal, South Africa and Vietnam as well as legacy areas such as Algeria, China, Egypt, Norway, the United Kingdom and the United States;

> In 2014 exploration expenditure amounted to €1,398 million, mainly related to the completion of 44 new exploratory wells (25.8 net to Eni). The overall commercial success rate was 31.3% (38.0% net to Eni). In addition, 101 exploratory wells drilled are in progress at year end (42.2 net to Eni).

Sustainability and portfolio developments

> The West Hub Development project in Block 15/06 (Eni operator with a 35% interest) achieved the first oil late in 2014. This is the first Eni-operated project in Angola and is currently flowing at 45 kbbl/d, with production ramp-up expected to reach a plateau of up to 100 kbbl/d in the coming months. The start-up was achieved in just 44 months from the announcement of the commercial discovery, a result that is at the top of the industry among deep waters developments;

> Production start-up achieved at the recent Nené discovery in block Marine XII (Eni operator with a 65% interest) in Congo, just 8 months after obtaining the production permit. The early production phase is yielding 7.5 kboe/d and the fast-track development of the field has leveraged on the synergies with the front-end loading and the infrastructures of the fields located in the area. The full-field development will take place in several stages, with a plateau of over 120 kboe/d;

> Sanctioned the integrated oil and gas project of the Offshore Cape Three Points (Eni operator with a 47.22% interest) in Ghana. First oil is expected in 2017, first gas in 2018 and production is expected to peak at 80 kboe/d;

> Projects to promote local development and to support local communities progressed with programmes in educational services, improving sanitary condition, access to water, socio-economic development activities, in particular in Congo, Ecuador, Indonesia, Iraq, Italy, Kazakhstan, Mozambique, Nigeria and Norway. In addition, the construction of educational facilities and programmes of access to water were performed in Pakistan, projects of employment and local business development in particular in Tunisia and Australia as well as activities of enhancement of cultural and environmental heritage;

> The Petroleum Technology Association of Nigeria recognized two Eni's subsidiaries as the best organizations to promote local content in the oil and gas sector in Nigeria (Local Content Operator). This award reaffirmed Eni's commitment in the implementation of effective initiatives to boost local economic activities also to achieve the high standard requirements in the oil and gas sector;

> Performed with the support of the Danish Institute for Human Rights and in line with the UN Guiding Principles on Business and Human Rights a preliminary assessment of the potential impacts of natural gas development on human rights in Mozambique;

> Development expenditure was €9,021 million (up by 5.1% from 2013) to fuel the growth of major projects and to maintain production plateau particularly in Norway, Angola, Congo, the United States, Italy, Nigeria, Egypt, Indonesia and Kazakhstan;

> In 2014 overall R&D expenditure of the Exploration & Production segment amounted to €83 million (€87 million in 2013).

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) re-balancing of exploration activities with a focus on near-field initiatives, with the objective of delivering 2 billion boe of discovered resources at a competitive cost of $2.6 per boe; (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 rate of 3.5% leveraging on a robust pipeline of projects with an average break-even of $45 per boe which together with the ramp-ups at fields started up in 2014 will add more than 650 kboe/d in 2018. This new production will bring an additional cumulative cash flow of €19 billion in the 2015-18 plan period. Main start-ups are the Goliat field (Eni operator with a 65% interest) in the Barents Sea in Norway, the oil and gas project of Offshore Cape Three Points (Eni operator with a 47.22% interest) in Ghana, the Jangkrik project (Eni operator with a 55% interest) in Indonesia and production re-start of Kashagan field (Eni's interest 16.81%) by the end of 2016; (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; and (iv) 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 current trends in 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 2015-18 plan period, Eni estimates a decrease of approximately 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 and service contract renegotiations. In addition, Eni intends to reduce operating costs by 7% versus the old plan; (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 growth mainly in countries with low-mid political risk (approximately 90% 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 (84% of production related to start-ups); and (iv) the technical risk related to the execution of drilling activities at high pressure/high temperature wells and deep waters wells (24% of planned wells to be drilled in 2015). Eni plans to increase operatorship of critical projects ensuring better direct control and deploying its high operational standards.

Reserves

Overview

The Company adopts comprehensive classification criteria for the estimate of proved, proved developed and proved undeveloped oil and gas reserves in accordance with applicable US Securities and Exchange Commission (SEC) regulations, as provided for in Regulation S-X, Rule 4-10.
Proved oil and gas reserves are those quantities of liquids (including condensates and natural gas liquids) and natural gas which, by analysis of geo-science 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 and gas reserves are inherently uncertain. Although authoritative guidelines exist regarding engineering criteria that have to be met before estimated oil and gas reserves can be designated as "proved", the accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and evaluation. Consequently, the estimated proved reserves of oil and natural gas may be subject to future revision and upward and downward revisions may be made to the 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 on the Profit Oil set contractually (Profit Oil). A similar scheme applies to service and buy-back 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[1]. D&M has also stated that the Company guidelines provide reasonable interpretation of facts and circumstances in line with generally accepted practices in the industry whenever SEC rules may be less precise. When participating in exploration and production activities operated by others entities, Eni estimates its share of proved reserves on the basis of the above guidelines.

The process for estimating reserves, as described in the internal procedure, involves the following roles and responsibilities: (i) the business unit managers (geographic units) and Local Reserves Evaluators (LRE) are in charge with estimating and classifying gross reserves including assessing production profiles, capital expenditure, operating expenses and costs related to asset retirement obligations; (ii) the petroleum engineering department at the head office verifies the production profiles of such properties where significant changes have occurred; (iii) geographic area managers verify the commercial conditions and the progress of the projects; (iv) the Planning and Control Department provides the economic evaluation of reserves; (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 "Politecnico di Torino" and received a Master of Science degree in Mining Engineering in 1985. She has more than 25 years of experience in the oil and gas industry and more than 15 years of experience in evaluating reserves.

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

Reserves independent evaluation

Since 1991, Eni has requested qualified independent oil engineering companies[2] to carry out an independent evaluation of part of its proved reserves on a rotational basis. The description of qualifications of the persons primarily responsible for the reserves audit is included in the third party audit report[3]. In the preparation of their reports, independent evaluators rely, without independent verification, upon information furnished by Eni 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, long-term development plans, future capital and operating costs.

In order to calculate the economic value of Eni's equity reserves, actual prices applicable to hydrocarbon sales, price adjustments required by applicable contractual arrangements and other pertinent information are provided by Eni to third party evaluators.

In 2014 Ryder Scott Company and DeGolyer and MacNaughton[3] provided an independent evaluation of approximately 27% of Eni's total proved reserves at December 31, 2014[4], confirming, as in previous years, the fairness of Eni internal evaluation.

In the 2012-2014 three year period, 94% of Eni total proved reserves were subject to independent evaluation. As at December 31, 2014, the principal Eni properties which did not subject to independent evaluation in the last three years were M'Boundi (Congo) and Junin 5 (Venezuela).

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 2014 estimated proved reserves were as follows:

(mmboe)	Consolidated subsidiaries	Equity-accounted entities	Total
Estimated net proved reserves at December 31, 2013	**5,708**	**827**	**6,535**
Extensions, discoveries, revisions of previous estimates and improved recovery, excluding price effect	610	11	621
Price effect	33		33
Reserves additions, total	643	11	654
Sales of minerals-in-place	(8)		(8)
Purchases of minerals-in-place	4		4
Production of the year	(575)	(8)	(583)
Estimated net proved reserves at December 31, 2014	**5,772**	**830**	**6,602**
Reserves replacement ratio, all sources (%)			112

(1) The reports of independent engineers are available on Eni website eni.com section Publications/Annual Report 2009.
(2) From 1991 to 2002, DeGolyer and MacNaughton; from 2003, also Ryder Scott.
(3) The reports of independent engineers are available on Eni website eni.com section Publications/Annual Report 2014.
(4) Includes Eni's share of proved reserves of equity accounted entities.

Additions to proved reserves booked in 2014 were 654 mmboe and derived from: (i) revisions of previous estimates were 524 mmboe mainly reported in Libya, Italy, Kazakhstan and Congo due to contractual revisions, continuous development activities and field performances; (ii) extensions and discoveries were up by 124 mmboe, with major increases booked in Ghana, Indonesia, the United States and Congo following new project sanctions and proved area extensions; (iii) improved recovery were up by 6 mmboe mainly reported in Algeria and Kazakhstan.
These increases compared to production of the year yielded an organic reserves replacement ratio[5] of 112%.
Price effects were negligible, leading to an upward revision of 33 mmboe, due to a lowered Brent price used in the reserves estimation process down to $101 per barrel in 2014 compared to $108 per barrel in 2013.
Sales of mineral-in-place mainly related to the divestment of assets in Nigeria (down 7 mmboe) and the United Kingdom (down 1 mmboe). Purchases of minerals-in-place referred mainly to interests in assets located in the United Kingdom (up 4 mmboe).
In 2014 Eni achieved an all sources reserves replacement ratio of 112%. Reserves life index was 11.3 years (11.1 years in 2013).

Proved undeveloped reserves

Proved undeveloped reserves as of December 31, 2014 totalled 3,169 mmboe, of which 1,333 mmboe of liquids mainly concentrated in Africa and Kazakhstan and 10,083 bcf of natural gas mainly located in Africa and Venezuela. Proved undeveloped reserves of consolidated subsidiaries amounted to 1,230 mmbbl of liquids and 6,466 bcf of natural gas.
In 2014, total proved undeveloped reserves increased by 61 mmboe mainly due to: (i) discoveries and extensions (up by 109 mmboe), in particular in Ghana and Indonesia associated to new project sanctions and proved area extensions; (ii) revisions of previous estimates (up by 173 mmboe) mainly reported in Libya, Nigeria, Angola, Italy and Norway due to contractual revisions, development activities and field performance; (iii) divestments (down by 4 mmboe) in Nigeria; and (iv) reclassification to proved developed reserves (down by 217 mmboe).
During 2014, Eni converted 217 mmboe of proved undeveloped reserves to proved developed reserves due to the progress of development activities and production start-ups. The main reclassifications to proved developed reserves are related to the following fields/projects: Hadrian South and Nikaitchuq (United States), A-LNG and Sangos (Angola), Karachaganak (Kazakhstan).
In 2014, capital expenditure amounted to approximately €2.3 billion and was made to progress the development of proved undeveloped reserves.
Reserves that remain proved undeveloped for five or more years are a result of several factors that affect the timing of the projects development and execution, such as the complex nature of the development project in adverse and remote locations, physical limitations of infrastructures or plant capacity and contractual limitations that establish production levels.
The Company estimates that approximately 1 bboe of proved undeveloped reserves have remained undeveloped for five years or more with respect to the balance sheet date, mainly related to: (i) the Kashagan project in Kazakhstan (approximately 0.5 bboe), which will be progressively reclassified to proved developed as a result of hooking-up new producing wells which are currently being drilled and plant capacity expansion as part of the completion of the sanctioned Phase 1 of the global development plan of the Kashagan field (the so-called Experimental Program); (ii) some 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 fulfilment of the contractual delivery quantities, Eni will implement phased production start-up from the relevant fields which are expected to be put in production over the next several years; and (iii) the Goliat project in Norway and other minor projects where development activities are progressing.

Delivery commitments

Eni sells crude oil and natural gas from its producing operations under a variety of contractual obligations. Some of these contracts, mostly relating to natural gas, specify the delivery of fixed and determinable quantities.
Eni is contractually committed under existing contracts or agreements to deliver in the next three years mainly natural gas to third parties for a total of approximately 331 mmboe from producing assets located mainly in Algeria, Australia, Egypt, Libya, Nigeria and Norway.
The sales contracts contain a mix of fixed and variable pricing formulas that are generally referenced to the market price for crude oil, natural gas or other petroleum products. Management believes it can satisfy these contracts from quantities available from production of the Company's proved developed reserves and supplies from third parties based on existing contracts. Production will account for approximately 77% of delivery commitments.
Eni has met all contractual delivery commitments as of December 31, 2014.

(5) 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		2012			2013			2014	
Italy	**227**	**1,633**	**524**	**220**	**1,532**	**499**	**243**	**1,432**	**503**
Developed	*165*	*1,325*	*406*	*177*	*1,266*	*408*	*184*	*1,192*	*401*
Undeveloped	*62*	*308*	*118*	*43*	*266*	*91*	*59*	*240*	*102*
Rest of Europe	**351**	**1,317**	**591**	**330**	**1,247**	**557**	**331**	**1,171**	**544**
Developed	*180*	*925*	*349*	*179*	*904*	*343*	*174*	*887*	*335*
Undeveloped	*171*	*392*	*242*	*151*	*343*	*214*	*157*	*284*	*209*
North Africa	**904**	**5,558**	**1,915**	**830**	**5,231**	**1,783**	**776**	**5,291**	**1,740**
Developed	*584*	*2,720*	*1,080*	*561*	*2,432*	*1,003*	*521*	*2,110*	*904*
Undeveloped	*320*	*2,838*	*835*	*269*	*2,799*	*780*	*255*	*3,181*	*836*
Sub-Saharan Africa	**672**	**2,061**	**1,048**	**723**	**2,374**	**1,155**	**739**	**2,744**	**1,239**
Developed	*456*	*1,429*	*716*	*465*	*1,295*	*701*	*470*	*1,271*	*702*
Undeveloped	*216*	*632*	*332*	*258*	*1,079*	*454*	*269*	*1473*	*537*
Kazakhstan	**670**	**2,038**	**1,041**	**679**	**1,957**	**1,035**	**697**	**2,049**	**1,069**
Developed	*203*	*1,401*	*458*	*295*	*1,488*	*566*	*306*	*1,553*	*589*
Undeveloped	*467*	*637*	*583*	*384*	*469*	*469*	*391*	*496*	*480*
Rest of Asia	**82**	**562**	**184**	**128**	**744**	**263**	**131**	**846**	**285**
Developed	*41*	*372*	*108*	*38*	*286*	*90*	*64*	*261*	*112*
Undeveloped	*41*	*190*	*76*	*90*	*458*	*173*	*67*	*585*	*173*
Americas	**154**	**449**	**236**	**147**	**509**	**240**	**147**	**468**	**232**
Developed	*109*	*334*	*170*	*96*	*310*	*153*	*116*	*393*	*188*
Undeveloped	*45*	*115*	*66*	*51*	*199*	*87*	*31*	*75*	*44*
Australia and Oceania	**24**	**572**	**128**	**22**	**848**	**176**	**13**	**807**	**160**
Developed	*24*	*459*	*107*	*20*	*561*	*123*	*12*	*675*	*135*
Undeveloped		*113*	*21*	*2*	*287*	*53*	*1*	*132*	*25*
Total consolidated subsidiaries	**3,084**	**14,190**	**5,667**	**3,079**	**14,442**	**5,708**	**3,077**	**14,808**	**5,772**
Developed	***1,762***	***8,965***	***3,394***	***1,831***	***8,542***	***3,387***	***1,847***	***8,342***	***3,366***
Undeveloped	***1,322***	***5,225***	***2,273***	***1,248***	***5,900***	***2,321***	***1,230***	***6,466***	***2,406***
Equity-accounted entities									
North Africa	**17**	**16**	**20**	**16**	**15**	**19**	**14**	**15**	**16**
Developed	*17*	*16*	*20*	*16*	*15*	*19*	*13*	*15*	*15*
Undeveloped							*1*		*1*
Sub-Saharan Africa	**16**	**353**	**81**	**15**	**330**	**75**	**17**	**351**	**81**
Developed							*7*	*89*	*23*
Undeveloped	*16*	*353*	*81*	*15*	*330*	*75*	*10*	*262*	*58*
Rest of Asia	**114**	**3,043**	**668**	**1**	**28**	**7**	**1**	**18**	**5**
Developed	*8*	*402*	*82*		*14*	*3*		*10*	*3*
Undeveloped	*106*	*2,641*	*586*	*1*	*14*	*4*	*1*	*8*	*2*
Americas	**119**	**3,355**	**730**	**116**	**3,353**	**726**	**117**	**3,353**	**728**
Developed	*19*	*6*	*20*	*19*	*5*	*18*	*26*	*6*	*26*
Undeveloped	*100*	*3,349*	*710*	*97*	*3,348*	*708*	*91*	*3,347*	*702*
Total equity-accounted entities	**266**	**6,767**	**1,499**	**148**	**3,726**	**827**	**149**	**3,737**	**830**
Developed	***44***	***424***	***122***	***35***	***34***	***40***	***46***	***120***	***67***
Undeveloped	***222***	***6,343***	***1,377***	***113***	***3,692***	***787***	***103***	***3,617***	***763***
Total including equity-accounted entities	**3,350**	**20,957**	**7,166**	**3,227**	**18,168**	**6,535**	**3,226**	**18,545**	**6,602**
Developed	*1,806*	*9,389*	*3,516*	*1,866*	*8,576*	*3,427*	*1,893*	*8,462*	*3,433*
Undeveloped	*1,544*	*11,568*	*3,650*	*1,361*	*9,592*	*3,108*	*1,333*	*10,083*	*3,169*

Oil and natural gas production

In 2014, Eni's liquids and gas production of 1,598 kboe/d increased by 0.6% from the 2013, excluding the impact of the divestment of Eni's interest in Siberian assets. The main production increases were reported in the United Kingdom, Algeria, the United States and Angola. These additions more than offset mature fields' declines. New fields' start-ups and continuing production ramp-ups contributed 126 kboe/day of production. The share of oil and natural gas produced outside Italy was 89% (unchanged compared with 2013).
Liquids production (828 kbbl/d) was barely unchanged from 2013 (down by 0.6%) with major increases reported in: (i) the United Kingdom due to the ramp-up of the Jasmine field (Eni's interest 33%) ; (ii) Algeria with the ramp-up of the El Merk field (Eni's interest 12.25%); (iii) the United States due to ramp-ups following development activities and optimization of operated projects of Nikaitchuq (Eni 100%), Pegasus (Eni 58%) and Appaloosa (Eni 100%); and (iv) Angola with the start-up of the West Hub project (Eni operator with a 35% interest).
Natural gas production (4,224mmcf/d) reported a slightly increase from 2013, excluding the impact of the divestment of Eni's interest in Siberian assets (up by 1.7%). The mature field declines were more than offset by the contribution of new field start-ups and ramp-ups.
Oil and gas production sold amounted to 549.5 mmboe. The 33.6 mmboe difference over production (583.1 mmboe) mainly reflected volumes of natural gas consumed in operations (29.4 mmboe), changes in inventories and other factors.
Approximately 62% of liquids production sold (299.8 mmbbl) was destined to Eni's Refining & Marketing segment (of which 23% was processed in Eni's refineries). About 27% of natural gas production sold (1,371 bcf) was destined to Eni's Gas & Power segment.
In 2014 oil spills due to operations reported a decrease compared to the previous year, amounting to 46%; oil spills from sabotage increased by 20.3%. Oil spills were concentrated mainly in Nigeria, due to disruptions and force majeure events reported during the year. Eni continues to promote operations aimed at raising safety standards and at ensuring efficient operations management. In particular, the prototype of the e-cube™ proprietary technology was successfully performed in the containment of underwater blow-out events. The application confirmed its technology to collect and convey on the surface the fluid output of well.

Oil and natural gas production[a]

	Liquids (mmbbl)	Natural gas (bcf)	Hydrocarbons (mmboe)	Liquids (mmbbl)	Natural gas (bcf)	Hydrocarbons (mmboe)	Liquids (mmbbl)	Natural gas (bcf)	Hydrocarbons (mmboe)
Consolidated subsidiaries	**2012**			**2013**			**2014**		
Italy	23	254	69	26	230	68	27	213	65
Rest of Europe	35	168	65	28	157	57	34	195	69
North Africa	98	632	213	91	609	201	91	627	206
Sub-Saharan Africa	90	196	125	88	176	120	84	185	118
Kazakhstan	22	81	37	22	78	36	19	73	32
Rest of Asia	15	143	41	16	130	40	13	114	34
Americas	26	104	46	22	89	38	27	80	41
Australia and Oceania	7	37	14	4	40	11	2	40	10
	316	**1,615**	**610**	**297**	**1,509**	**571**	**297**	**1,527**	**575**
Equity-accounted entities									
North Africa	1	2	2	1	2	2	1	2	1
Sub-Saharan Africa	1	2	1		5	1		4	1
Rest of Asia	1	29	6	2	61	13		8	2
Americas	4		4	4		4	4		4
	7	**33**	**13**	**7**	**68**	**20**	**5**	**14**	**8**
Total	**323**	**1,648**	**623**	**304**	**1,577**	**591**	**302**	**1,541**	**583**

(a) Includes volumes of gas consumed in operations (29.4, 30 and 25.5 mmboe in 2014, 2013 and 2012, respectively).

Oil and natural gas production[a]

	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		**2012**			**2013**			**2014**	
Italy	**63**	**695.1**	**189**	**71**	**630.2**	**186**	**73**	**583.8**	**179**
Rest of Europe	**95**	**458.4**	**178**	**77**	**429.6**	**155**	**93**	**535.2**	**190**
Croatia		25.4	5		43.0	8		38.2	7
Norway	74	289.6	126	60	250.5	106	62	274.2	112
United Kingdom	21	143.4	47	17	136.1	41	31	222.8	71
North Africa	**267**	**1,728.2**	**581**	**248**	**1,668.7**	**551**	**248**	**1,718.9**	**562**
Algeria	71	40.1	78	73	81.6	88	83	141.3	109
Egypt	88	805.9	235	93	734.6	227	88	649.8	206
Libya	101	863.5	258	76	836.7	228	73	911.2	239
Tunisia	7	18.7	10	6	15.8	8	4	16.6	8
Sub-Saharan Africa	**245**	**534.3**	**343**	**242**	**481.7**	**329**	**231**	**507.5**	**323**
Angola	78	34.8	85	79	32.7	84	75	38.3	82
Congo	82	120.5	104	90	161.8	120	80	145.1	106
Nigeria	85	379.0	154	73	287.2	125	76	324.1	135
Kazakhstan	**61**	**221.7**	**102**	**61**	**213.5**	**100**	**52**	**200.7**	**88**
Rest of Asia	**41**	**390.1**	**112**	**43**	**354.7**	**108**	**36**	**310.4**	**93**
China	8	4.4	9	7	3.4	8	4		4
India		10.5	2		7.2	1		3.7	1
Indonesia	1	58.9	12	1	55.0	11	1	52.6	11
Iran	3		3	4		4	1		1
Iraq	18		18	22		22	21		21
Pakistan	1	310.4	57		283.1	52		248.2	45
Turkmenistan	10	5.9	11	9	6.0	10	9	5.9	10
Americas	**72**	**283.5**	**124**	**61**	**244.5**	**106**	**74**	**217.8**	**115**
Ecuador	25		25	13		13	12		12
Trinidad & Tobago		58.5	11		58.6	11		60.3	11
United States	47	225.0	88	48	185.9	82	62	157.5	92
Australia and Oceania	**18**	**100.8**	**37**	**10**	**110.4**	**30**	**6**	**110.5**	**26**
Australia	18	100.8	37	10	110.4	30	6	110.5	26
	862	**4,412.1**	**1,666**	**813**	**4,133.3**	**1,565**	**813**	**4,184.8**	**1,576**
Equity-accounted entities									
Angola	2	4.4	2		14.2	3		10.3	2
Brazil	2		2						
Indonesia	1	26.0	6	1	24.2	5	1	23.2	5
Russia	2	52.4	11	5	141.6	31			
Tunisia	4	5.3	5	4	5.5	5	4	5.3	5
Ukraine		0.5							
Venezuela	9		9	10	0.8	10	10	0.8	10
	20	**88.6**	**35**	**20**	**186.3**	**54**	**15**	**39.6**	**22**
Total	**882**	**4,500.7**	**1,701**	**833**	**4,319.6**	**1,619**	**828**	**4,224.4**	**1,598**

(a) Includes volumes of gas consumed in operations (442, 451 and 383 mmcf/d in 2014, 2013 and 2012 respectively).

Productive wells

In 2014 oil and gas productive wells were 8,777 (3,518.1 of which represented Eni's share). In particular, oil productive wells were 6,087 (2,272.4 of which represented Eni's share); natural gas productive wells amounted to 2,690 (1,245.7 of which represented Eni's share).

The following tables show 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 at Dec. 31, 2014[a]

	2014			
	Oil wells		Natural gas wells	
(units)	Gross	Net	Gross	Net
Italy	241.0	195.1	615.0	532.4
Rest of Europe	354.0	60.6	188.0	102.9
North Africa	1,710.0	907.0	210.0	89.0
Sub-Saharan Africa	2,950.0	589.8	341.0	25.7
Kazakhstan	149.0	41.1		
Rest of Asia	475.0	363.0	956.0	364.9
Americas	201.0	112.0	366.0	127.5
Australia and Oceania	7.0	3.8	14.0	3.3
	6,087.0	**2,272.4**	**2,690.0**	**1,245.7**

(a) Includes 2,234 gross (799.1 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 2014, a total of 44 new exploratory wells were drilled (25.8 of which represented Eni's share), as compared to 53 exploratory wells drilled in 2013 (27.8 of which represent Eni's share) and 60 exploratory wells drilled in 2012 (34.1 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 31.3% (38.0% net to Eni) as compared to 36.9% (38.5% net to Eni) in 2013 and 40% (40.8% net to Eni) in 2012.

Exploratory Well Activity

	Net wells completed						Wells in progress at Dec. 31[a]	
	2012		2013		2014		2014	
(units)	Productive	Dry[b]	Productive	Dry[b]	Productive	Dry[b]	Gross	Net
Italy	1.0					0.6	4.0	2.8
Rest of Europe	1.0	1.0		3.4		4.3	12.0	3.3
North Africa	6.3	11.3	4.9	5.4	3.5	4.3	13.0	10.3
Sub-Saharan Africa	4.5	5.1	3.2	6.6	7.3	7.3	49.0	16.9
Kazakhstan		0.8		0.4			6.0	1.1
Rest of Asia	0.5	0.6	4.3	2.7	1.3	4.3	12.0	5.0
Americas		0.1	0.2	1.2	2.0	1.4	4.0	2.5
Australia and Oceania		0.4		0.5		0.9	1.0	0.3
	13.3	**19.3**	**12.6**	**20.2**	**14.1**	**23.1**	**101.0**	**42.2**

(a) Includes temporary suspended wells pending further evaluation.
(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.

Development

In 2014 a total of 440 development wells were drilled (191 of which represented Eni's share) as compared to 463 development wells drilled in 2013 (187.2 of which represented Eni's share) and 351 development wells drilled in 2012 (163.6 of which represented Eni's share).
The drilling of 142 wells (46.5 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						Wells in progress at Dec. 31	
	2012		2013		2014		2014	
(units)	Productive	Dry[a]	Productive	Dry[a]	Productive	Dry[a]	Gross	Net
Italy	18.0	1.0	7.4	1.0	12.5		5.0	4.6
Rest of Europe	2.9	0.6	6.3		9.8	1.0	36.0	7.9
North Africa	46.0	1.6	61.6	3.3	54.5	1.0	15.0	7.4
Sub-Saharan Africa	27.4	0.3	26.3	1.2	31.6		23.0	7.5
Kazakhstan	1.4		0.3		1.5		22.0	3.9
Rest of Asia	41.2	0.1	61.7	4.3	54.2	1.6	19.0	8.2
Americas	23.1		13.8		22.1	0.7	20.0	6.5
Australia and Oceania					0.1	0.4	2.0	0.5
	160.0	**3.6**	**177.4**	**9.8**	**186.3**	**4.7**	**142.0**	**46.5**

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

Acreage

In 2014 Eni performed its operations in 40 countries located in five continents. As of December 31, 2014, Eni's mineral right portfolio consisted of 938 exclusive or shared rights of exploration and development activities for a total acreage of 334,739 square kilometres net to Eni of which developed acreage of 40,771 square kilometres and undeveloped acreage of 293,968 square kilometres net to Eni.
In 2014, changes in total net acreage mainly derived from: (i) new leases mainly in South Africa, Indonesia, Vietnam, Myanmar, Portugal, China, Egypt, Greenland, Australia and Kenya for a total acreage of approximately 76,000 square kilometres; (ii) interest increase in Indonesia and Ireland for a total acreage of approximately 2,100 square kilometres; (iii) the total relinquishment of licences mainly in Togo, Pakistan, Australia, Poland, Democratic Republic of Congo, covering an acreage of approximately 12,000 square kilometres; (iv) partial relinquishment or interest reduction in Indonesia, Norway, Congo and Angola for approximately 6,000 square kilometres.
In addition, Eni has been granted three prospection permits in Algeria for a net acreage of approximately 23,000 square kilometres.

Oil and natural gas interests

	December 31, 2013	December 31, 2014						
	Total net acreage[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	**37,938**	**265**	**15,883**	**53,444**	**69,327**	**10,948**	**33,894**	**44,842**
Italy	**17,282**	**151**	**10,712**	**10,751**	**21,463**	**8,989**	**8,308**	**17,297**
Rest of Europe	**20,656**	**114**	**5,171**	**42,693**	**47,864**	**1,959**	**25,586**	**27,545**
Croatia	987	2	1,975		1,975	987		987
Cyprus	10,018	3		12,523	12,523		10,018	10,018
Greenland	920	2		4,890	4,890		1,909	1,909
Norway	3,779	56	2,255	9,149	11,404	345	3,327	3,672
Poland	969							
Portugal		3		9,099	9,099		6,370	6,370
United Kingdom	638	35	941	343	1,284	627	117	744
Other Countries	3,345	13		6,689	6,689		3,845	3,845
AFRICA	**137,096**	**282**	**66,114**	**263,572**	**329,686**	**20,032**	**139,309**	**159,341**
North Africa	**20,412**	**117**	**32,559**	**15,675**	**48,234**	**14,144**	**7,549**	**21,693**
Algeria	1,179	42	3,222	187	3,409	1,148	31	1,179
Egypt	3,665	54	4,926	6,800	11,726	1,772	3,174	4,946
Libya	13,294	10	17,947	8,688	26,635	8,950	4,344	13,294
Tunisia	2,274	11	6,464		6,464	2,274		2,274
Sub-Saharan Africa	**116,684**	**165**	**33,555**	**247,897**	**281,452**	**5,888**	**131,760**	**137,648**
Angola	4,443	72	6,555	14,605	21,160	813	3,514	4,327
Congo	3,125	28	1,714	2,649	4,363	921	1,962	2,883
Democratic Republic of Congo	263							
Gabon	7,615	6		7,615	7,615		7,615	7,615
Ghana	1,664	3		4,676	4,676		1,664	1,664
Kenya	38,930	7		61,363	61,363		40,426	40,426
Liberia	1,841	3		7,365	7,365		1,841	1,841
Mozambique	5,103	1		10,207	10,207		5,103	5,103
Nigeria	7,646	40	25,286	10,837	36,123	4,154	3,484	7,638
South Africa		1		82,117	82,117		32,847	32,847
Togo	6,192							
Other Countries	39,862	4		46,463	46,463		33,304	33,304
ASIA	**79,314**	**71**	**17,556**	**199,150**	**216,706**	**5,809**	**103,428**	**109,237**
Kazakhstan	**869**	**6**	**2,391**	**2,542**	**4,933**	**442**	**427**	**869**
Rest of Asia	**78,445**	**65**	**15,165**	**196,608**	**211,773**	**5,367**	**103,001**	**108,368**
China	5,149	8	77	7,056	7,133	19	7,056	7,075
India	6,167	11	206	16,546	16,752	109	6,058	6,167
Indonesia	19,209	14	3,218	31,608	34,826	1,217	25,031	26,248
Iran	820							
Iraq	446	1	1,074		1,074	446		446
Myanmar		2		7,850	7,850		7,065	7,065
Pakistan	10,335	17	10,390	15,249	25,639	3,396	6,071	9,467
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	200	1	200		200	180		180
Vietnam	10,783	6		39,569	39,569		26,384	26,384
Other Countries	3,244	1		14,600	14,600		3,244	3,244
AMERICAS	**8,286**	**306**	**5,064**	**11,746**	**16,810**	**3,273**	**4,670**	**7,943**
Ecuador	1,985	1	1,985		1,985	1,985		1,985
Trinidad & Tobago	66	1	382		382	66		66
United States	3,843	290	1,895	4,197	6,092	954	2,546	3,500
Venezuela	1,066	6	802	2,002	2,804	268	798	1,066
Other Countries	1,326	8		5,547	5,547		1,326	1,326
AUSTRALIA AND OCEANIA	**13,622**	**14**	**1,140**	**21,679**	**22,819**	**709**	**12,667**	**13,376**
Australia	13,622	14	1,140	21,679	22,819	709	12,667	13,376
Total	**276,256**	**938**	**105,757**	**549,591**	**655,348**	**40,771**	**293,968**	**334,739**

(a) Square kilometres.
(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

In the Val d'Agri concession (Eni's interest 60.77%) the development plan is progressing in line with the commitments agreed with the Basilicata Region in 1998: (i) the construction of a new gas treatment unit is designed to improve the environmental performance of the treatment centre; (ii) continuous improvement of the Environmental Monitoring Plan, which represents a benchmark in terms of environmental protection. This was underpinned by an Action Plan for Biodiversity in Val d'Agri; and (iii) programs to support a cultural and social development, tourism as well as development of agricultural and food farming businesses.
Other main development activities concerned the completion of development activities to achieve start-up of Fauzia and Elettra fields located in the Adriatic Sea as well as ongoing maintenance and efficiency improvement activities on Italian energetic grid.
Ongoing activities progressed to perform the environmental monitoring, protection and clean-up of the Adriatic coastal area in cooperation with the district of Ravenna.
In November 2014, Eni signed a Memorandum of Understanding with the Ministry of Economic Development, Confindustria and other local public bodies to promote and support integrated Oil&Gas business initiatives with socio-economic project in the area in order to ensure an economic sustainable value in the long-term.

Rest of Europe

Norway Exploration activities yielded positive results with the oil and gas Drivis discovery made at the offshore licence PL532 (Eni 30%), with volumes in place estimated in a range of 125 to 140 million barrels. The discovery will be put into production with the recent oil and gas discoveries of Skrugard, Havis and Skavl by means of the development of the integrated Johan Castberg Hub. The total recoverable resources of the licence are estimated at over 600 million barrels at 100%.
In January 2015, Eni was awarded: (i) the operatorship and a 40% interest in the PL 806 licence located in the Barents Sea; and (ii) a 13.12% interest in the PL 044C licence located in the North Sea.
Development activities progressed at the Goliat field (Eni operator with a 65% interest) in the Barents Sea. Start-up is expected in the second half of 2015, with a production plateau at approximately 65 kboe/d net to Eni in 2016.
During the year, the implementation of an oil spill contingency and response plan progressed by developing techniques and methodologies in response to oil spills. The performed activities in the drilling phases were acknowledged by the Norwegian Authorities as the benchmark for oil spill reaction in the coastal areas. The project was launched by Eni and its partner in the program jointly with the Norwegian Clean Seas Association for Operating Companies (NOFO) and involved other oil companies operating in the oil and gas exploration in the Barents Sea as well as local and international research institutes. The achieved results were presented to the Norwegian Environmental Agency, the local administrations and all stakeholders. These results reaffirmed that the Goliat project is equipped with a well-advance emergency system for the management of oil spills, in terms of organization, consolidation of the emergency apparatus, as well as equipment and technology advancement.
Other ongoing activities concerned programs of enhancement of cultural heritage of Sami local community and of technical and professional skills development of local communities.
Development activities progressed to: (i) maintain and optimize production at the Ekofisk field (Eni's interest 12.39%) by means of drilling of infilling wells, upgrading of existing facilities and optimization of water injection; and (ii) fine-tuning activities at the Midgard and Mikkel fields (Eni's interest 14.9%).

United Kingdom Exploration activities yielded positive results with the Romeo North discovery, already linked to the production platform of the Jade field (Eni 's interest 7%).
During the year Eni was awarded the operatorship of the 22/19c (Eni's interest 50%), 22/19e (Eni's interest 57.14%) and 30/1b (Eni's interest 100%) exploration blocks in the North Sea. In April 2014, Eni completed the acquisition of the Liverpool Bay assets (Eni's interest 100%).
Development activities mainly concerned: (i) production start-up of the West Franklin field (Eni's interest 21.87%) with the completion of the Phase 2 development program by means of the installation of production platform and pipeline to linkage to the treatment facility in the area; and (ii) production ramp-up of the Jasmine project (Eni's interest 33%) with the completion of commissioning and start-up of 4 additional production wells.

North Africa

Algeria Eni was granted three prospection permits in the Timimoun and Oued Mya areas, in southern onshore Algeria. The agreements expire in two years and cover a total acreage of 46,837 square kilometres. The program includes studies and drilling of prospection wells to assess the mineral potential.
Production ramp-up of the El Merk project (Eni's interest 12.25%) was completed in the year and a production plateau of approximately 18 kboe/d net to Eni was achieved.
Development and optimization activities progressed at the MLE-CAFC production fields (Eni operator with a 75% interest). The project includes an additional oil phase with start-up expected in 2017, targeting a production plateau of approximately 33 kboe/d net to Eni

Egypt Exploration activities yielded positive results with: (i) the oil discovery ARM-14 in the Abu Rudeis licence (Eni's interest 100%) in the Gulf of Suez. The discovery was linked to the nearby production facilities and a double production level was achieved in 2014; and (ii) the oil discovery West Deep in the Meleiha concession (Eni's interest 76%) that flowed at approximately 2 kbbl/d in test production. The discovery confirms the mineral potential of the deep area in the western desert which was identified leveraging on the application of the e-dva™ proprietary technology for processing seismic 3D imaging. Additional delineation and development wells will be drilled to achieve a production level of approximately 8 kbbl/d by the end of 2015. These discoveries

are characterized by a fast time-to-market and are in line with Eni's strategy of focusing on high value exploration activities and synergic assets.
In 2014 Eni was awarded: (i) the operatorship of the South-West Meleiha three onshore exploration licences (Eni's interest 100%), nearby the Meleiha concession, and the Block 9 (Eni's interest 100%) and Block 8 (Eni's interest 50%) located in the deep offshore of the Mediterranean Sea. The closing was achieved in the early 2015 with the ratification of the relevant concession agreements; (ii) the Shorouk concession (Eni's interest 100%) in the deep offshore of the Mediterranean Sea.
In March 2015 Eni and the Egyptian Ministry of Petroleum and Mineral Resources signed a framework agreement to develop the oil and gas resources in the Country with an estimated investment of $5 billion at 100%. The investments, which will be utilized through the realization of projects to be implemented in the next 4 years, are directed to the development of 200 million barrels of oil and 1.3 Tcf of gas.
In August 2014, the DEKA project (Eni operator with a 50% interest) started up with a production of approximately 64 mmcf/d of gas and 800 barrels/day of associated condensates. Produced gas is being processed at the onshore El Gamil plant. Peak production of approximately 230 mmcf/d net to Eni is expected by the first quarter of 2015.
Development activities concerned: (i) infilling activities at the Belayim (Eni's interest 100%), Ha'py (Eni's interest 50%), El Temsah (Eni operator with a 50% interest) and Pourt Fouad (Eni's interest 100%) fields to optimize the mineral potential recovery factor; (ii) start-up of the END Phase 3 sub-sea project (Eni's interest 50%).

Sub-Saharan Africa

Angola Exploration activities yielded positive results with: (i) the Ochigufu 1 NFW discovery in the deep water of the Block 15/06 (Eni operator with a 35% interest) with a potential in place estimated at approximately 300 million barrels of oil, increasing resources of the West Hub project. The exploration activity was performed with an innovative 3D seismic acquisition. In January 2015 Eni obtained from the Angolan authorities a three-year extension of the exploration period of the above mentioned block; (ii) the appraisal of the Pinda FM discovery in the Block 0 (Eni's interest 9.8%).
In November 2014, Eni signed with the national oil company Sonangol a strategic agreement on future co-operation activities. In particular the agreement includes the studies to analyze the potential of the non-associated gas present in the Lower Congo Basin and offshore Angola. The project scope is to analyze the different options both internationally and in the domestic market, also in order to sustain the local economy. In addition the companies will asses possible projects on the mid-downstream business to be carried out in Angola.
In December 2014, first oil was achieved at the West Hub Development Project in Block 15/06 in the deep offshore. This first Eni-operated producing project in the country is currently producing 45 kboe/d through the N'Goma FPSO, with a production ramp-up expected to reach a plateau up to 100 kboe/d in the coming months. The start-up was achieved in just 44 months from the announcement of the commercial discovery, a result that is at the top of the industry for development in deep waters. The N'Goma FPSO is currently producing from the Sangos discovery, future production will leverage the progressive hooking up of the Block's discoveries.
The main development activities performed in the year concerned: (i) the progress of the Nemba field project in Block 0 to reduce flaring gas. In 2015, once the project is completed, flared gas is expected to decrease by approximately 85% from current level; (ii) the Mafumeira Sul field (Eni's interest 9.8%) with start-up expected in 2016; (iii) the Lianzi project in the Block 14K/A Imi Unit Area (Eni's interest 10%), with start-up expected in the second half of 2015 and production plateau of 35 kboe/d; (iv) the Kizomba satellites Phase 2 project (Eni's interest 20%). The project provides to put into production three additional discoveries that will be linked to the existing FPSO. Start-up is expected in 2015, with a production plateau of 70 kboe/d in 2016.

Congo Exploration activities yielded positive results in the Marine XII offshore block (Eni operator with a 65% interest) with: (i) the Nené Marine 3 appraisal well confirming the oil and gas mineral potential of the area; and (ii) the significant Minsala Marine oil discovery with resources in place of 1 billion boe. Exploration activities used the application of the e-dva™ proprietary technology for processing seismic imaging that allowed an optimal positioning of exploration wells.
In July 2014, a cooperation agreement was signed with the relevant authorities to extend existing oil permits and to develop new initiatives in the Country's coastal basin, which extends from onshore Mayombe to frontage deep waters.
At the end of December 2014 was achieved the start-up of the recent Nené Marine discovery in block Marine XII just 8 months after obtaining the production permit. The early production phase is yielding 7,500 boe/d and the fast-track development of the field has leveraged on the synergies with the front-end loading and the infrastructures of the fields located in the area. The full-field development will take place in several stages and will include the installation of production platforms and the drilling of approximately 30 wells, with a plateau of over 120 kboe/d.
The flaring down project of the M'Boundi field was completed during the year with a decrease of approximately 64 mmcf in daily volumes of gas flaring, thus achieving the zero flaring target in the area. In particular, the associated gas was fully valorised through: (i) a program of gas injection in order to optimize reserve recovery; (ii) a long-term supply contract to power plants in the area including the CEC Centrale Electrique du Congo plant (Eni's interest 20%) with a 300 MW generation capacity. In 2014 M'Boundi contractual supplies (Eni operator with an 83% interest) were approximately 106 mmcf/d (approximately 17 kboe/d net to Eni). These facilities will also receive volumes of gas from the offshore discoveries of the Marine XII block in the future.
Project Integrée Hinda (PIH) progressed to support the population in the M'Boundi area. The social project provides to improve education, health, production capacity in agriculture with specific programs and in collaboration with local authorities. Planned activities for the 2011-2015 periods achieved a work progressing of 80% at the end of 2014. The

program involved approximately 25,000 people. Eni with the support of the Earth Institute of the Columbia University launched a program to design a monitoring system to assess the effectiveness of the PIH project and to check its support to the development of the area.
In addition, local cultural promotion programs started-up with specific activities in the Pointe Noire area, Makoua, located in the north of the country and Brazzaville capital city.
Development of the Litchendjili sanctioned project progressed in the Marine XII block. The project provides for the installation of a production platform, the construction of transport facilities and onshore treatment plant. Start-up is expected in the second half of 2015 with a peak production of 12 kboe/d net to Eni. Production will also feed the CEC power station.

Mozambique Exploration activities yielded positive results with the appraisal gas wells Agulha 2 and Coral 4 DIR, confirming the extension of their respective discoveries. The exploration activity was underpinned by the utilization of the e-dva™ proprietary technology of processing seismic imaging. The potential in place in Area 4 is estimated at 88 tcf (Eni operator with a 50% interest).
The Company is planning to develop as first target the Coral discovery and a portion of the Mamba straddling resources. As part of the Mamba plan, based on the enactment of a law decree which defines the fiscal and contractual regime applicable to onshore liquefaction projects, Eni expects to obtain the necessary authorizations to develop and produce up to 12 tcf from the straddling reservoir via an independent industrial plan which needs to be coordinated with the operator of Area 1. An Unitisation Agreement for the straddling resources has to be agreed among concessionaries of the straddling reservoirs and submitted to the Mozambique Government within six months dating back to the enactment of the special law on onshore projects which occurred in December 2014.
The Coral project scheme comprises construction of a floating unit for the treatment, liquefaction and storage of natural gas (Floating LNG - FLNG) fed by subsea wells. The development plan was formally submitted to the local Authorities at the end of 2014. The FID is expected in the second half of 2015. The award of the relevant EPCIC contracts for the construction, installation and commissioning of the floating unit is expected by the end of 2015. Production start-up is expected for the end of 2019.
The development plan of the first stage of the Mamba project contemplates construction and commissioning of two onshore LNG trains and the drilling of 16 subsea wells, with start-up in 2022. The scheduled activities comprise: (i) the submission of the Declaration of Commerciality to the Government by the third quarter of 2015; (ii) the filing of the development plan by the end of 2015; and (iii) the finalization of the commercial agreements and the project financing by the first quarter of 2016. The FID is expected in 2016-2017.
In October 2014, Eni signed with the South Korean Company KOGAS a cooperation agreement for jointly development opportunities in the upstream and LNG areas, in particular in the Area 4 in Mozambique.
Leveraging on Eni's cooperation model, a medium-long term program was defined to support local communities also involving all local stakeholders as part of the development activity of the gas discoveries in the Country. The guideline of the program includes projects to develop the socio-economic conditions of local communities and respect for biodiversity. In particular, during 2014 certain projects were completed in the Pemba area in order to: (i) support the access to education, with the construction of a primary school; (ii) develop training activities in collaboration with National Institute for Employment and Vocational Training (INEFP) also supplying educational materials; and (iii) enhance the national health service, also with the restructuring of some hospital departments and specific course dedicated to health staff.
In the Pemba area ongoing activities also concerned: (i) access to water with construction of a supply system for approximately 4,000 people; and (ii) studies of access to energy for rural communities also with renewable energy supplies. In addition, the construction of a gas fired power plant for domestic consumption is being planned with the support of the Mozambican government.
Eni performed with the support of the Danish Institute for Human Rights and in line with the UN Guiding Principles on Business and Human Rights a preliminary assessment of the potential impacts of the natural gas development projects on human rights in the Country.

Nigeria Exploration activities yielded positive results with the Abo 12 oil well in the OML 125 block (Eni operator with an 85% interest). The discovery will be linked to facilities of Abo field during 2015.
The treatment and re-injection of produced water program started up at the Ebocha flowstation in the OML 61 block (Eni operator with a 20% interest). The project provides for the treatment of 60 kbbl/d of produced water. Associated gas program progressed with further reductions of gas flared.
In the year production start-up was achieved at the Bonga NW field in the OML 118 block (Eni's interest 12.5%) with the drilling and completion of 4 production and 2 injection wells.
Development activities progressed at the OML 28 block (Eni's interest 5%): (i) the drilling campaign progressed within the integrated oil and natural gas project in the Gbaran-Ubie area. The development plan provides for the supply of natural gas to the Bonny liquefaction plant by means of the construction of a Central Processing Facility (CPF) with a treatment capacity of approximately 1 bcf/d of gas and 120 kbbl/d of liquids; and (ii) the development plan of the Forkados-Yokri field includes the drilling of 24 producing wells, the upgrading of existing flowstations and the construction of transport facilities. Start-up is expected in 2015.
The project of the Kwale-Akri pipeline in the Niger Delta is almost completed. The e-vpms™ (eni-vibroacoustic pipeline monitoring system) proprietary technology installed with the aim of identify leaks in real time and significantly reducing bunkering.
During the year, supporting programs for the local community progressed with main activities in the construction of public infrastructure, improving the quality

of education services, enhancing of basic health services, expanding the access to energy for local area, as well as training programs to promote the economic development, in particular in the agricultural sector.
Eni launched a website to report the sustainability activity performed in the Country. In particular, information and data related to oil spills, gas flared emissions and a summary on the environmental impact studies are available.
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 a design treatment capacity of approximately 1,236 bcf/y of feed gas corresponding to a production of 22 mmtonnes/y of LNG on six trains. The seventh unit is being engineered as it is in the planning phase. When fully operational, total capacity will amount to approximately 30 mmtonnes/y of LNG, corresponding to a feedstock of approximately 1,624 bcf/y. Natural gas supplies to the plant are provided under gas supply agreements with a 20-year term from the SPDC JV and the NAOC JV, the latter operating the OMLs 60, 61, 62 and 63 blocks with an overall amount of approximately 2,825 mmcf/d (approximately 268 mmcf/d net to Eni corresponding to approximately 49 kboe/d). LNG production is sold under long-term contracts and exported to European, Asian and US markets by the Bonny Gas Transport fleet, wholly owned by Nigeria LNG Co.
In 2014 the Petroleum Technology Association of Nigeria recognized two Eni's subsidiaries as the best organizations to promote local content in the oil and gas sector in Nigeria (Local Content Operator). This award reaffirmed the Eni's commitment in the implementation of effective initiatives to boost local economic activities also to achieve the high standard requirements in the oil and gas sector.

Kazakhstan

Kashagan During the course of 2014, the Consortium performed an assessment of the technical issues which forced the operator to shut down the production at the Kashagan field (Eni's interest 16.81%) soon after the production start-up with the effective completion of Phase 1 of the development plan (the Experimental Program). The findings of the assessment confirmed the necessity to fully replace the damaged pipelines. The Consortium recently finalized the contracts for the replacement of both oil and gas lines. The Consortium expects to complete the installation works in the second half of 2016 with production re-start by the end of 2016. The planned production rate will be achieved during 2017.
The Phase 1 is targeting an initial production capacity of 180 kbbl/d; when a second offshore treatment train comes online and compression facilities for gas reinjection are operational production capacity will ramp up to 370 kbbl/d. The partners are planning to further increase available production capacity up to 450 kbbl/d by installing additional gas compression capacity for reinjection in the reservoir. The partners submitted the scheme of this additional phase to the relevant Kazakh Authorities.
In December 2014 the Consortium and the Kazakh Government signed an agreement which settled a number of pending issues relating to financial, environmental and operational matters.
The Consortium agreed a new setup of the operating model to execute the development of the project, targeting to streamline decision-making process, to increase efficiency in operations and to reduce costs. This new operating model provides that a company, participated by the seven partners of the Consortium, acts as the sole operator of all exploration, development and production activities at the Kashagan field. As part of this process, in 2014 the shareholding in Agip Kazakhstan North Caspian Operating Company NV (Eni's interest 100%) was transferred to NCOC BV. The activities needed to set up the new operating model will be completed by the first half of 2015.
An innovative environmental monitoring system was implemented in 2014. The project designed by Eni provides for the application of a mobile underwater vehicle (AUV) able to realize an environmental monitoring and asset integrity at the production facility.
During the year the integrated program for the management of biodiversity in the Ural Delta (Ural River Park Project - URPP) was completed. The program was launched by Eni under the sponsorship of the Environment and Water Resources Kazakh Authority and aimed to protect the environment and ecosystems in the Caspian area. In June 2014 the project received an official UNESCO designation to be included in the Man and Biosphere Program.
Within the agreements reached with the local Authorities, Eni continues its training program for Kazakh resources in the oil&gas sector.
As of December 31, 2014, the aggregate costs incurred by Eni for the Kashagan project capitalized in the financial statements amounted to $8.5 billion (€7.0 billion at the EUR/USD exchange rate of December 31, 2014). This capitalized amount included: (i) $6.2 billion relating to expenditure incurred by Eni for the development of the oilfield; and (ii) $2.3 billion relating primarily to accrue finance charges and expenditures for the acquisition of interests in the North Caspian Sea PSA consortium from exiting partners upon exercise of pre-emption rights in previous years.
As of December 31, 2014 Eni's proved reserves booked for the Kashagan field amounted to 580 mmboe, barely unchanged compared to 2013.

Karachaganak The Expansion Project of the Karachaganak field (Eni's interest 29.25%) is currently being assessed by the consortium by means of the installation, in stages, of gas treatment plants and re-injection facilities to support liquids production plateau and increase gas marketable volumes. Phase-one development to increase injection and treatment capacity of natural gas are under economical and technical assessment. Further development projects to support liquids production plateau are under study.
Eni continues its involvement to support local communities by means of the construction of schools and educational facilities as well as water supply plant and road infrastructures for the villages located in the nearby area of Karachaganak, in particular in the western area.
As of December 31, 2014 Eni's proved reserves booked for the Karachaganak field amounted to 489 mmboe, barely unchanged compared to 2013.

Rest of Asia

Indonesia Exploration activities yielded positive results with a gas discovery through the Merakes 1 NFW exploration well in the East Sepinggan offshore block (Eni operator with an 85% interest). This discovery with a potential in place estimated at approximately 2 Tcf, is located in proximity of the operated field of Jangkrik (Eni operator with a 55% interest), which is currently under development, and will supply additional gas volumes to the Bontang LNG plant. Exploration activity was performed leveraging on the innovative seismic analysis to allow an effective activities by means of the evaluation of several geological data.
Main ongoing activities to feed the Bontang plant concerned: (i) the Jangkrik field in the Kalimantan offshore. The project includes drilling of production wells linked to a Floating Production Unit for gas and condensate treatment as well as construction of a transportation facility. Start-up is expected in 2017; (ii) the Bangka project (Eni's interest 20%) in the eastern Kalimantan, with start-up expected in 2016.
Other main activities were performed on the environmental protection, health care and educational system to support local communities located in the operated area of the eastern Kalimantan, Papua and North Sumatra.

Iran The formal hand over of operations to local partners at the Darquain project is completed. Eni's involvements essentially will consist of finalizing the reimbursement of its past investments.

Iraq In 2014 phase one of the Rehabilitation Plan of the Zubair field (Eni's interest 41.6%) progressed. The project includes the construction of an oil treatment plant for a capacity of 300 kbbl/d, the revamping of existing treatment facilities and the drilling of production and water injection wells.
In March 2014 the national oil company South Oil Company sanctioned the Enhanced Redevelopment Plan to achieve a production plateau of 850 kbbl/d. The main contracts to build new facilities were awarded in the first half of 2014.
Activities to support local farms and communities progressed during the year.

Russia The drilling exploration programme was halted due to the sanctions enacted by European Union and the United States. Eni is closely monitoring developments of the situation and has required all relevant authorizations to continue the exploration activities in compliance with the current sanction regime against Russia.

Turkmenistan In November 2014, Eni and the State Agency for Management and Use of Hydrocarbon Resources signed an addendum to the Production Sharing Agreement regulating exploration and production activities at the onshore Nebit Dag Area. The addendum extends the duration of the PSA to 2032. The agreement also establishes the transfer of a 10% stake out of the contractor share to the State oil company Turkmenneft (Eni retains a 90% interest stake). The agreement also includes the construction of the Training Center for technical staff in the upstream sector. Vocational training programme in oil&gas sector progressed for local graduates.
In addition, Eni and Turkmen State Agency signed a Memorandum of Understanding to evaluate the extension of Eni's activities also in the Turkmenistan's offshore section of the Caspian Sea.
Development activities include: (i) a program to mitigate the natural field production decline; and (ii) the completion of the revamping of the treatment oil plant at the Burun field in order to increase treatment capacity as well as to improve safety, efficiency and environment performance also by means of reducing gas flaring and increasing water re-injection capacity.

Americas

Ecuador Exploration activities yielded positive results with the Oglan-2 exploration well in Block 10 (Eni operator with a 100% interest) with a potential in place estimated at 300 million barrels of oil, located near the processing facilities of the operated field of Villano.
In the year, the following projects were sanctioned: (i) the phase VI of the Villano field, with a production start-up expected in 2016; (ii) Oglan discovery, with start-up expected in 2017.
Maintenance activities and facilities upgrading progressed to support high safety standard and efficiency levels.
In 2014 the first three years of the Plan of Action on Biodiversity in the Amazon forest near the Villano field, concluded that Eni's production activities were performed with minimal environmental impacts.
Eni's commitment to support the socio-economic development nearby the production areas progressed by means of: (i) improving sanitary condition with medical supplies, equipments and vehicles; (ii) educational plans with the construction of schools, supplies and scholarship foundation; and (iii) training activities and programmes to develop agricultural sector also with specific equipments supplies.

United States Exploration activities yielded positive results with the Stallings 1H and Mitchell 1H exploratory wells, under the agreement with Quicksilver Resources signed at the end of 2013 providing for joint evaluation, exploration and development of unconventional oil reservoirs (shale oil) in the southern part of the Delaware Basin in West Texas. The wells were already connected to existing production facilities with an initial flow of 1,500 bbl/d.
Eni was awarded the operatorship of exploration licences MC246 and MC290 (Eni's interest 100%) in the Gulf of Mexico and in the Leon Valley (Western Texas) with a 50% interest for exploring and developing an area with unconventional oil reservoirs.
Production start-up was achieved at the St. Malo (Eni's interest 1.25%) and Lucius (Eni 8.5%) fields, the latter started up in January 2015. The start-up of Hadrian South (Eni's interest 30%) is achieved in March 2015 and will allow to achieve an expected peak production of 144 kboe/d (22 kboe/d net to Eni) for the Lucius-Hadrian South project.
Development activities concerned: (i) the Heidelberg project (Eni's interest 12.5%) in the deep offshore of the Gulf of Mexico. Activities include the drilling of 5 production wells and the installation of a production platform. Start-up is expected at

the end of 2016 with a production of 9 kboe/d net to Eni; (ii) the drilling of development wells at the operated Devils Tower (Eni's interest 75%) and Pegasus (Eni's interest 85%) fields as well as non-operated Europa (Eni's interest 32%) and K2 (Eni's interest 13.39%) fields; and (iii) the development of unconventional gas reserves (shale gas) in the Alliance area (Eni's interest 27.5%) with start-up of additional 21 production wells.
Drilling activities progressed at the Nikaitchuq (Eni operator with a 100% interest) and Oooguruk (Eni's interest 30%) fields in Alaska. In June 2014, the Nikaitchuq field achieved the production target of 25 kboe/d. This relevant result required the expertise and the application of Eni's proprietary technologies in an area with extreme climate and environmental constraints, which helped to build one of the most advanced production facilities in the North Slope, with maximum environmental compatibility and high operating efficiency.

Venezuela Drilling activities progressed at the giant Junin 5 field (Eni's interest 40%) with 35 bbbl of certified heavy oil in place, located in the Orinoco Oil Belt. Early production of the first phase started up in 2013 with a target plateau of 75 kbbl/d. The Full Field development includes a long-term production plateau of 240 kbbl/d. The project provides for the construction of a refinery. Eni agreed to finance a part of PDVSA's development costs for the Early production phase and engineering activity of refinery plant up to $1.74 billion.
Ongoing development activities progressed at the giant Perla gas field in the Cardon IV block (Eni's interest 50%), located in the Gulf of Venezuela.

The early production start-up is expected by the second quarter of 2015 with a target production of approximately 460 mmcf/d. The project includes the utilization of the existing discovery/appraisal wells, the drilling of 17 additional wells and the installation of production platforms linked by pipelines to an onshore treatment plant. Production ramp-up is expected in 2017 with a target of approximately 800 mmcf/d. The development plan targets a long-term production plateau of approximately 1,200 mmcf/d in 2020.

Capital expenditure

Capital expenditure of the Exploration & Production segment (€10,524 million) concerned mainly development of oil and gas reserves (€9,021 million) directed mainly outside Italy, in particular in Norway, Angola, Congo, the United States, Nigeria, Egypt, Indonesia and Kazakhstan. Development expenditures in Italy in particular concerned the well drilling program and facility upgrading in Val d'Agri as well as sidetrack and workover activities in mature fields.
About 98% of exploration expenditures (€1,398 million) were directed outside Italy in particular to Libya, Mozambique, the United States, Nigeria, Angola, Indonesia, Cyprus, Norway and Gabon. In Italy, exploration activities were directed mainly to the Adriatic offshore, Val d'Agri and Po Valley.
In 2014 overall expenditure in R&D amounted to €83 million (€87 million in 2013). A total of 15 new patent applications were filed.

Capital expenditure (€ million)	2012	2013	2014	Change	% Ch.
Acquisition of proved and unproved properties	**43**	**109**		**(109)**	**..**
North Africa	14	109			
Sub-Saharan Africa	27				
Americas	2				
Exploration	**1,850**	**1,669**	**1,398**	**(271)**	**(16.2)**
Italy	32	32	29	(3)	(9.4)
Rest of Europe	151	357	188	(169)	(47.3)
North Africa	153	95	227	132	..
Sub-Saharan Africa	1,142	757	635	(122)	(16.1)
Kazakhstan	3	1		(1)	..
Rest of Asia	193	233	160	(73)	(31.3)
Americas	80	110	139	29	26.4
Australia and Oceania	96	84	20	(64)	(76.2)
Development	**8,304**	**8,580**	**9,021**	**441**	**5.1**
Italy	744	743	880	137	18.4
Rest of Europe	2,008	1,768	1,574	(194)	(11.0)
North Africa	1,299	808	832	24	3.0
Sub-Saharan Africa	1,931	2,675	3,085	410	15.3
Kazakhstan	719	658	521	(137)	(20.8)
Rest of Asia	641	749	1,105	356	47.5
Americas	953	1,127	921	(206)	(18.3)
Australia and Oceania	9	52	103	51	(98.1)
Other expenditure	**110**	**117**	**105**	**(12)**	**(10.3)**
	10,307	**10,475**	**10,524**	**49**	**0.5**