Exploration & Production

KEY PERFORMANCE INDICATORS

		2025	2024	2023
Total Recordable Injury Rate (TRIR)[(a)]	(total recordable injuries/worked hours) X 1,000,000	**0.55**	0.46	0.43
of which: employees		***0.73***	*0.18*	*0.48*
contractors		***0.50***	*0.52*	*0.41*
Profit per boe[(b)]	($/boe)	**7.80**	3.69	8.58
Opex per boe[(d)]		**9.2**	9.2	8.6
Cash flow per boe		**20.5**	17.3	19.4
Finding & Development cost per boe[(c)(d)]		**17.0**	22.7	26.3
Average hydrocarbon realization		**53.64**	57.56	59.35
Production of hydrocarbons[(d)]	(kboe/d)	**1,728**	1,707	1,655
Net proved reserves of hydrocarbons[(d)]	(mmboe)	**6,885**	6,497	6,614
Reserves life index	(years)	**10.9**	10.4	10.6
Organic reserves replacement ratio	(%)	**167**	124	69
Employees at year end	(number)	**9,141**	9,188	9,840
of which: outside Italy		***5,101***	*5,171*	*5,927*
Direct GHG emissions (Scope 1)[(a)]	(Mt CO_2eq.)	**4.6**	6.7	7.6
Volumes of hydrocarbon sent to routine flaring[(a)]	(billion Sm³)	**0.0**	0.1	0.2
Total volume of oil spills (>1 barrel)[(a)]	(barrels)	**4**	2,163	5,132
Re-injected produced water[(a)]	(%)	**56**	51	42

(a) KPIs refer to 100% of the operated assets, consolidated and unconsolidated, with reference to the operatorship criteria expressed in the standards for Sustainability Statement.
(b) Related to consolidated subsidiaries.
(c) Three-year average.
(d) Includes Eni's share of equity-accounted entities.

PERFORMANCE OF THE YEAR

- TRIR (Total recordable injury rate) of the workforce was 0.55, representing an increase compared to the previous year due to portfolio operations closed in 2024 and higher injury events occurred to employees. Performance improved for contractors.
- Hydrocarbon production averaged 1,728 kboe/d, up by 1% from 2024, enabled by accelerated and smooth start-ups and ramp-ups and excellent base business performance. Underlying production growth was 4% compared to 2024.
- Net proved reserves at December 31, 2025 amounted to 6.9 bboe based on a reference Brent price of 70 $/barrel. The all sources replacement ratio was 162%. The reserves life index was 10.9 years (10.4 years in 2024).
- Volumes of hydrocarbon sent to routing flaring achieved zero routine flaring during 2025 due to effect of the portfolio optimization activities and the completion of gas valorization projects in Congo.
- Total volume of oil spills was nearly zeroed (4 barrels in 2025). During the period, no oil spills due to sabotage occurred.
- Re-injected produced water was 56% and increased compared to 2024 due to higher volumes re-injected in Turkmenistan, Mexico and Italy.
- Direct GHG emissions (Scope 1) amounted to 4.6 million tonnes of CO_2eq, reflecting decrease compared to 2024 due to portfolio optimization and actions aimed at improving performance through the reduction of non-routine flaring.

PORTFOLIO

- Signed a binding agreement with Petronas, Malaysian state-owned company, to establish a jointly controlled venture to combine the two partners' gas-rich assets of Indonesia and Malaysia, featuring two very complementary portfolios able to generate operational and financial synergies. In line with Eni's satellite model of setting geographically focused, the new JV company will be financially self-sufficient entity to target over 500 kboe/d of production in the medium term. The transaction completion is subject to governmental, regulatory, and partner approval.
- Within Eni's strategy of optimizing its upstream portfolio by accelerating the monetization of exploration discoveries through the divestment of equity stakes, in 2025 finalized the sale of a 30% stake in the Baleine project in Côte d'Ivoire to Vitol and in January 2026 signed a binding agreement with SOCAR, the State Oil Company of the Republic of Azerbaijan, for the sale of an additional 10% stake in the project.
- Signed with the Argentina YPF the Final Technical Project Description (FTPD), a significant step towards the Final Investment Decision for the 12 MTPA integrated upstream-midstream Argentina LNG (ARGLNG) project intended to monetize the gas reserves of the Vaca Muerta basin. Through a phased approach, the project could be scaled up to 30 MTPA in the long-term. In February 2026, Eni and YPF signed a binding Joint Development Agreement (JDA) with XRG, part of the ADNOC Group, to advance Argentina LNG.
- In line with Eni's strategy focused on the rationalization of the upstream activities by rebalancing its portfolio and divesting non-strategic assets, Eni closed the divestment of an asset in Congo while finalized farm-in agreement with acquisition of additional interest in Norway (via Eni's 63% owned associate Vår Energi), in the United Kingdom (through Eni's 36% owned associate Ithaca Energy) as well as in Algeria and Nigeria.

EXPLORATION

- In 2025, resource additions from exploration activity total about 900 million boe, extending a more than 10 year run of organic replacement of production. In particular, significant discoveries in several geographies were:
  - the JV Azule Energy (Eni 50%) confirmed a significant discovery in Namibia with the Sagittarius-1X gas and condensates well, the Capricornus 1-X oil well, and a further gas and condensate discovery at the Volans-1X well. Azule Energy also announced a discovery on Angola's first dedicated gas exploration well, Gajajeira-01;
  - in Norway (through Vår Energi) with discoveries in the Barents Sea and Norwegian Sea nearby to existing production facilities;
  - in Indonesia with discoveries close to existing facilities or to discoveries already made, provide significant synergies for the development;
  - in Egypt, with discoveries in the Western Desert, already put into production;
  - in Côte d'Ivoire, where discovery confirmed the eastern extension of the Baleine field;
  - in Ghana with appraisal activity at the Eban-Akoma field in the Cape Three Points 4 block.

- Reloading exploration portfolio with the addition of approximately 21,200 square kilometers with new leases in Algeria, Egypt, Italy, Côte d'Ivoire, Norway and Tunisia.
- Signed a farm-in agreement with YPF to acquire a 50% interest and operatorship of the exploration Block OFF-5 in the Uruguay offshore, further strengthening the collaboration between Eni and YPF. The agreement is subject to the approval of the relevant Uruguayan authorities. The block further consolidates Eni's exploration portfolio, which combines near-field prospects and exploration activities that provide synergies with existing facilities as well as diversified and selected high-impact opportunities leveraging on Eni's proprietary technologies to accelerate and maximize their value.
- Signed a new exploration contract in Côte d'Ivoire for the CI-707 offshore block, geologically continuous with the nearby CI-205 block, where Eni announced the Calao discovery in March 2024. This proximity offers an opportunity for future synergistic developments.
- Signed a new hydrocarbons contract with Eni's partner Sonatrach for the exploration and development of the Zemoul El Kbar area. The contract, with a duration of 30 years, covers a development and exploration area of about 4,200 square kilometers and also includes neighboring assets previously under separate contracts. This new agreement follows the recent award, in the context of 2024 Algeria Bid Round, of the Reggane II block to Eni in partnership with PTTEP.
- In 2025 exploration expenses were €211 million (€741 million in 2024) and included the write-off of unsuccessful wells and of unproved exploration rights, amounting to €37 million (€555 million in 2024) associated to projects with negative outcome. In particular, exploration and appraisal activities comprised of write-offs of unsuccessful exploration wells costs for €20 million mainly in the Algeria and Oman. Write-offs of €17 million are related to exploration licenses because the Company decided to stop pursuing the underlying initiatives. In addition, 147 exploratory drilled wells are in progress at year end (62.3 net to Eni).

DEVELOPMENT

- Among the production start-up highlights of the year, we can count:
  - in Congo, launched at the end of the year the Phase 2 of the Congo FNLG project, ahead of project schedule, by means of the production start-up at the Nguya FLNG floating liquefaction unit, increasing production capacity to 3 MTPA overall. The Nguya FLNG was designed and built in only 33 months, from contract award to sail away, setting a record for time-to-market in the entire sector;
  - in Indonesia, gas production start-up of the Merakes East field in the East Sepinggan offshore block (Eni operator with an 85% interest) in the Kutei basin, which will contribute to approximately 18 kboe/d to Eni's production;
  - in Angola, start-up of the the Agogo Integrated West Hub project, operated by the JV Azule Energy in block offshore 15/06, ten months ahead of project schedule. The project includes the development of two fields, Agogo and Ndungu, with combined reserves of approximately 450 million barrels and an expected production plateau of 180 kboe/d;
  - in Angola, inauguration by Azule of the gas treatment plant for the NGC project, the first non-associated gas project in the country, feeding the Angola LNG export plant and the domestic market. First gas production into plant was reached in February 2026;
  - in Norway, through Vår Energi, production start-up of the Balder X oilfield with production expected to rise to approximately 80 kbbl/d and of the Johan Castberg oilfield with a gross capacity of 220 kbbl/d as well as the Askeladd West gas field to ensure full capacity of the Hammerfest LNG plant in the next years;
  - in Ghana, started workover activities of the Sankofa East field, nearby to the John Agyekum Kufour FPSO, as part of the broader Sankofa field's development plan.
- Signed agreements with Egypt and Cyprus to develop gas reserves of the Block 6 offshore Cyprus, operated by Eni, which will enable Cyprus gas to be exported to international markets through the existing Eni's infrastructure in Egypt.
- Eni and Petroci announced a significant increase in gas supply for Côte d'Ivoire's power generation system. The gas produced, up to 70 mmcf/d, will be entirely allocated to meet local demand, ensuring a reliable supply for the country's power generation needs and further reinforcing Côte d'Ivoire's role as a regional energy hub.
- Launched the new Yasika logistics platform, a strategic infrastructure within the Phase 2 of the Congo FNLG project. The platform will support operations for the Tango and Nguya floating liquefaction units and for the construction of new installations, interconnection of existing infrastructures, and modernization of strategic facilities, such as the Litchendjili plant.
- Reached the Final Investment Decision by Eni and its partners CNPC, ENH, Kogas, and XRG to develop the Coral North FLNG project which will put in production the gas volumes from the northern part of Area 4 Coral gas reservoir, in the Rovuma basin, through a floating LNG facility with 3.6 MTPA production capacity. The project will leverage Eni's fast-track approach and expertise from the Coral South project and is expected to start-up in just three years.
- Eni and its Offshore Cape Three Points (OCTP) project partners, Vitol and the Ghana National Petroleum Corporation (GNPC), signed a Memorandum of Intent with the Government of Ghana, finalized to the country's oil and gas production increase and new sustainable

initiatives. The collaboration focuses also on the evaluation of exploration activities and the new potential development of the Eban-Akoma field in the Cape Three Points Block 4.
- Signed collaboration agreements with the UAE companies for the development of data centers in Italy which will be fully powered by blue power supplied by Eni, a lower carbon energy source generated by natural gas power plants, whose CO_2 emissions are captured and stored. The agreements also include renewable energy capacity transmission through cross border interconnection between Albania and Italy as well as and critical minerals, further strengthening the collaboration between Eni and the United Arab Emirates. In addition, signed with the Khazna Data Centers, a global leader in hyperscale digital infrastructure, a Heads of Terms to set up a joint venture aimed at the development of an "AI Data Center Campus" with a total IT capacity of 500 MW in Ferrera Erbognone, in Lombardia region.
- Development expenditure amounted to €5.5 billion, in particular in the United Arab Emirates, Libya, Egypt, Indonesia, Algeria, Congo and Italy.
- In 2025, overall R&D expenditure amounted to €34 million (€41 million in 2024).

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 US 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 S&P Global Energy, 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 equity interest to total proved reserves of the contractual area, until expiration of the relevant mineral right. Eni's proved reserves entitlements at PSAs are calculated so that the sale of production entitlements cover expenses incurred by the Group for field development (Cost Oil) and recognize a share of profit set contractually (Profit Oil). A similar scheme applies to service contracts.

Reserves governance

Eni retains rigorous control over the process of booking proved reserves, through a centralized model of reserves governance. The Reserves Department of the Exploration & Production segment is in charge of: (i) ensuring the periodic certification process of proved reserves; (ii) 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 stated that those guidelines comply with the SEC rules[1]. D&M has also stated that the Company guidelines provide reasonable interpretation of facts and circumstances in line with generally accepted practices in the industry whenever SEC rules may be less precise.
When participating in exploration and production activities operated by other entities, Eni estimates its share of proved reserves on the basis of the above guidelines, while for certain joint ventures and associates Eni relies on the annual certification of independent petroleum engineering companies.

(1) The reports of independent engineers are available on sec.gov in "Item 19 - Exhibits" of the Annual Report on Form 20-F 2009.

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

Eni's Head of Reserves holds a Master's degree in Petroleum Engineering from the Polytechnic of Turin and 5-years Degree in Civil Hydraulic Engineering from the Alma Mater Studiorum - University of Bologna. He has more than 20 years of experience in the upstream industry and in reserves evaluation.

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

Reserves independent evaluation

Eni has its proved reserves audited on a rotational basis by independent oil engineering companies[2]. The description of qualifications of the persons primarily responsible for the reserves audit is included in the third-party audit report. In the preparation of their reports, independent evaluators rely upon information furnished by Eni, without independent verification, with respect to property interests, production, current costs of operations and development, sales agreements, prices and other factual information and data that were accepted as represented by the independent evaluators.

These data, equally used by Eni in its internal process, include logs, directional surveys, core and PVT (Pressure Volume Temperature) analysis, maps, oil/gas/water production/injection data of wells, reservoir studies, technical analysis relevant to field performance, development plans, future capital and operating costs.

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

The volumes and monetary values of the reserves of certain joint venture and affiliated companies are certified on their behalf in a similar manner by independent petroleum engineering companies and provided to Eni[3].

In 2025[4], Ryder Scott Company, Sproule and DeGolyer and MacNaughton provided an independent evaluation of approximately 36%[5] of Eni's total proved reserves at December 31, 2025, confirming, as in previous years, the reasonableness of Eni internal evaluation. In the 2023-2025 three-year period, 82% of Eni total proved reserves were subject to an independent evaluation.

(2) For the past three years we have utilized independent certification services of DeGolyer and MacNaughton, Ryder Scott and Sproule.
(3) In 2025 Azule Energy and Vår Energi.
(4) The reports of independent engineers are available on Eni website eni.com section Publications/Annual Report 2025.
(5) Includes Azule Energy and Vår Energi for which Eni received a Third Party Letter.

Movements in net proved reserves

Eni's net proved reserves were determined taking into account Eni's share of proved reserves of equity accounted entities. Movements in Eni's 2025 proved reserves were as follows:

(mmboe)	Consolidated subsidiaries	Equity-accounted entities	Total
Estimated net proved reserves at December 31, 2024	**4,433**	**2,064**	**6,497**
Extensions, discoveries, revisions of previous estimates and improved recovery, excluding price effect	910	155	1,065
Price effect	9	(21)	(12)
Reserve additions, total	919	134	1,053
Portfolio	(63)	29	(34)
Production of the year	(459)	(172)	(631)
Estimated net proved reserves at December 31, 2025	**4,830**	**2,055**	**6,885**
Reserves replacement ratio, all sources (%)			**162**

Net proved reserves as of December 31, 2025 were 6,885 mmboe, of which 4,830 mmboe of consolidated subsidiaries. Net additions to proved reserves were 1,053 mmboe and derived from: (i) new discoveries and extensions of 633 mmboe mainly related to booking of reserves as a result of progression activities in Indonesia (563 mmboe), Norway (48 mmboe), the United Arab Emirates (13 mmboe) and other minor projects in Netherlands, the United Kingdom and Angola; (ii) revisions of previous estimates were positive for 387 mmboe. The main positive revisions were in Egypt, Algeria, Norway, the United Arab Emirates and Côte d'Ivoire. The main negative changes were reported in Australia and Italy. Revisions to previous estimates include a negative price effect of 12 mmboe, mainly due to the change in the Brent benchmark marker from 81 $/barrel in 2024 to 70 $/barrel in 2025. This price change led to the removal of reserves which have become uneconomical in the 2025 scenario and net lower reserves entitlements under PSA contracts; and (iii) improved recovery of 33 mmboe were reported in Iraq and Côte d'Ivoire.

Portfolio activities provided net negative additions of 34 mmboe and comprised: (i) the sale of 30% stake in the Baleine project in Côte d'Ivoire and of an asset in Congo (down 70 mmboe); (ii) assets acquisitions in Norway through Vår Energi (Eni 63%), in the United Kingdom via Ithaca Energy (Eni 36%) and the acquisition of additional stake in Touat field in Algeria and Bonga in Nigeria (overall up 36 mmboe).The organic[6] and all sources reserves replacement ratio was 167% and 162%, respectively. The reserves life index was 10.9 years (10.4 years in 2024). For further information, please see the additional information on Oil & Gas producing activities required by the SEC in the notes to the consolidated financial statements.

(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		**2025**			**2024**			**2023**	
Italy	**197**	**651**	**320**	**213**	**817**	**368**	**211**	**859**	**374**
Developed	*123*	*524*	*223*	*129*	*693*	*262*	*136*	*653*	*261*
Undeveloped	*74*	*127*	*97*	*84*	*124*	*106*	*75*	*206*	*113*
Rest of Europe		**81**	**15**		**54**	**10**	**27**	**174**	**60**
Developed		*45*	*9*		*52*	*10*	*24*	*167*	*56*
Undeveloped		*36*	*6*		*2*		*3*	*7*	*4*
North Africa	**517**	**5,052**	**1,483**	**458**	**5,338**	**1,479**	**523**	**5,935**	**1,658**
Developed	*339*	*2,562*	*829*	*291*	*2,692*	*805*	*326*	*3,181*	*935*
Undeveloped	*178*	*2,490*	*654*	*167*	*2,646*	*674*	*197*	*2,754*	*723*
Sub-Saharan Africa	**252**	**1,664**	**570**	**268**	**1,931**	**638**	**334**	**2,479**	**809**
Developed	*202*	*1,099*	*412*	*187*	*1,206*	*418*	*225*	*1,350*	*482*
Undeveloped	*50*	*565*	*158*	*81*	*725*	*220*	*109*	*1,129*	*327*
Kazakhstan	**556**	**1,399**	**824**	**591**	**1,489**	**876**	**637**	**1,546**	**933**
Developed	*523*	*1,396*	*789*	*539*	*1,486*	*823*	*576*	*1,546*	*872*
Undeveloped	*33*	*3*	*35*	*52*	*3*	*53*	*61*		*61*
Rest of Asia	**713**	**4,009**	**1,480**	**578**	**1,583**	**881**	**485**	**1,303**	**733**
Developed	*274*	*920*	*449*	*233*	*799*	*385*	*240*	*725*	*379*
Undeveloped	*439*	*3,089*	*1,031*	*345*	*784*	*496*	*245*	*578*	*354*
Americas	**111**	**80**	**127**	**127**	**94**	**145**	**213**	**131**	**238**
Developed	*80*	*56*	*91*	*81*	*56*	*92*	*163*	*107*	*184*
Undeveloped	*31*	*24*	*36*	*46*	*38*	*53*	*50*	*24*	*54*
Australia and Oceania		**62**	**11**		**190**	**36**		**192**	**37**
Developed		*37*	*7*		*23*	*5*		*58*	*11*
Undeveloped		*25*	*4*		*167*	*31*		*134*	*26*
Total consolidated subsidiaries	**2,346**	**12,998**	**4,830**	**2,235**	**11,496**	**4,433**	**2,430**	**12,619**	**4,842**
Developed	***1,541***	***6,639***	***2,809***	***1,460***	***7,007***	***2,800***	***1,690***	***7,787***	***3,180***
Undeveloped	***805***	***6,359***	***2,021***	***775***	***4,489***	***1,633***	***740***	***4,832***	***1,662***
Equity-accounted entities									
Rest of Europe	**381**	**1,229**	**617**	**391**	**939**	**572**	**326**	**515**	**425**
Developed	*295*	*692*	*427*	*207*	*545*	*311*	*167*	*359*	*235*
Undeveloped	*86*	*537*	*190*	*184*	*394*	*261*	*159*	*156*	*190*
North Africa	**5**	**249**	**53**	**8**	**222**	**50**	**6**	**14**	**8**
Developed	*5*	*249*	*53*	*8*	*222*	*50*	*6*	*14*	*8*
Undeveloped									
Sub-Saharan Africa	**192**	**3,077**	**781**	**226**	**3,103**	**819**	**207**	**1,501**	**494**
Developed	*112*	*1,222*	*346*	*103*	*1,054*	*305*	*107*	*1,036*	*305*
Undeveloped	*80*	*1,855*	*435*	*123*	*2,049*	*514*	*100*	*465*	*189*
Rest of Asia	**111**	**1,418**	**381**	**110**	**1,411**	**379**	**110**	**1,406**	**378**
Developed									
Undeveloped	*111*	*1,418*	*381*	*110*	*1,411*	*379*	*110*	*1,406*	*378*
Americas	**20**	**1,063**	**223**	**23**	**1,159**	**244**	**26**	**1,260**	**267**
Developed	*20*	*1,063*	*223*	*23*	*1,159*	*244*	*26*	*1,260*	*267*
Undeveloped									
Total equity-accounted entities	**709**	**7,036**	**2,055**	**758**	**6,834**	**2,064**	**675**	**4,696**	**1,572**
Developed	***432***	***3,226***	***1,049***	***341***	***2,980***	***910***	***306***	***2,669***	***815***
Undeveloped	***277***	***3,810***	***1,006***	***417***	***3,854***	***1,154***	***369***	***2,027***	***757***
Total including equity-accounted entities	**3,055**	**20,034**	**6,885**	**2,993**	**18,330**	**6,497**	**3,105**	**17,315**	**6,414**
Developed	***1,973***	***9,865***	***3,858***	***1,801***	***9,987***	***3,710***	***1,996***	***10,456***	***3,995***
Undeveloped	***1,082***	***10,169***	***3,027***	***1,192***	***8,343***	***2,787***	***1,109***	***6,859***	***2,419***

Proved undeveloped reserves

Proved undeveloped reserves as of December 31, 2025 totaled 3,027 mmboe. At year-end, proved undeveloped reserves of liquids amounted to 1,082 mmbbl and of natural gas amounted to 10,169 bcf, mainly concentrated in Africa and Asia. Proved undeveloped reserves of consolidated subsidiaries amounted to 805 mmbbl of liquids and 6,359 bcf of natural gas. The table below provide a summary of changes in total proved undeveloped reserves for 2025:

(mmboe)	
Proved undeveloped reserves as of December 31, 2024	**2,787**
Transfers to proved developed reserves	(370)
Extensions and discoveries	585
Revisions of previous estimates	23
Improved recovery	26
Portfolio	(24)
Proved undeveloped reserves as of December 31, 2025	**3,027**

During 2025, Eni matured 370 mmboe of proved undeveloped reserves to proved developed reserves due to progress in development activities, production start-ups and project revisions. The main reclassifications to proved developed reserves related to the fields/projects in the following countries: Norway (through Vår Energi), the United Arab Emirates and Azule Energy in Angola. For further information, please see the additional information on Oil & Gas producing activities required by the SEC in the notes to the consolidated financial statements.
In 2025, capital expenditure amounted to approximately €10 billion to progress the development of PUDs.
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 complexity of development project in adverse and remote locations, physical limitations of infrastructures or plant capacity and contractual limitations that establish production levels. The proved undeveloped reserves that have remained undeveloped for five years or more at the balance sheet date amounted to 0.75 bboe, decreasing from 2024, and are mainly related to the following projects where executions and developments activities are in progress: (i) certain Libyan gas fields (0.45 bboe) where production start-ups are planned according to the delivery obligations set forth in a long-term gas supply agreement currently in force; (ii) certain fields in the United Arab Emirates (0.15 bboe); and (iii) other fields in Italy and Iraq (0.15 bboe). Eni remains strongly committed to put these projects into production in the coming years. The length of the development period depends on a range of external factors, such as for example the type of development, the location and physical operating environment of the field or the absence of infrastructure, considering that the majority of our projects are infrastructure-driven, and not a function of internal factors, such as an insufficient devotion of resources by Eni or a diminished commitment on the part of Eni to complete the project.

Delivery commitments

Eni, through consolidated subsidiaries and equity-accounted entities, sells crude oil and natural gas from its producing operations under a variety of contractual obligations. Some of these contracts, mostly relating to natural gas, specify the delivery of fixed and determinable quantities.
Eni is contractually committed under existing contracts or agreements to deliver in the next three years mainly natural gas to third parties for a total of approximately 624 mmboe from producing assets located mainly in Algeria, Australia, Egypt, Ghana, Indonesia, Kazakhstan, Libya, Mozambique, Nigeria, Norway and Venezuela.
The sales contracts contain a mix of fixed and variable pricing formulas that are generally indexed to the market price for crude oil, natural gas or other petroleum products. Management believes it can satisfy these contracts from quantities available mainly from production of the Company's proved developed reserves. Production is expected to fully account of delivery commitments.
Eni has met all contractual delivery commitments as of December 31, 2025.

OIL AND GAS PRODUCTION

In 2025, hydrocarbons production averaged 1,728 kboe/d, up by 1% compared to 2024. Excellent project development performance was delivered in production start-ups and ramp-ups in Norway, Côte d'Ivoire, Mexico, Congo, Angola, Indonesia and Ghana. This was supplemented by excellent base business regularity. Offsetting these effects were mature fields declines and tail asset divestments closed in 2024 in Nigeria, Alaska, and Congo.
Liquids production was 840 kbbl/d, up by 7% compared to 2024. The organic growth in Côte d'Ivoire due to the start of Baleine Phase 2, Mexico, Angola and Norway was partly offset by divestments and mature fields declines.
Natural gas production was 4,644 mmcf/d, down by 4% compared to 2024, due to the divestments and mature fields decline partly offset by organic growth in Congo (Marine XII) and Indonesia (Merakes East) as well as at our satellites in Angola/Norway.
Oil and gas production sold amounted to 566 mmboe. The 65 mmboe difference over production (631 mmboe) mainly reflected volumes of natural gas consumed in operations (49 mmboe), changes in inventory levels and other variations.

ANNUAL 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		2025[(c)]			2024			2023	
Italy	**9**	**76**	**24**	**10**	**72**	**23**	**10**	**77**	**25**
Rest of Europe		**24**	**5**	**6**	**71**	**19**	**7**	**40**	**14**
Netherlands		24	5		24	5			
United Kingdom				6	47	14	7	40	14
North Africa	**64**	**668**	**191**	**65**	**778**	**214**	**69**	**813**	**225**
Algeria	21	116	43	20	134	46	23	122	46
Egypt	23	343	88	22	419	102	24	478	116
Libya	20	206	59	22	222	65	21	210	62
Tunisia		3	1	1	3	1	1	3	1
Sub-Saharan Africa	**39**	**179**	**74**	**32**	**164**	**63**	**31**	**160**	**61**
Congo	9	86	25	10	76	24	13	63	25
Côte d'Ivoire	14	20	18	6	9	8	2	2	2
Ghana	5	42	13	4	33	11	5	32	11
Nigeria	11	31	18	12	46	20	11	63	23
Kazakhstan	**42**	**89**	**59**	**40**	**92**	**58**	**42**	**93**	**60**
Rest of Asia	**35**	**233**	**79**	**34**	**215**	**75**	**31**	**187**	**67**
China									
Indonesia	1	174	34	1	183	35		149	29
Iraq	11	30	17	10	25	15	9	28	14
Timor Leste								3	1
Turkmenistan	1	22	5	2	3	3	2	3	3
United Arab Emirates	22	7	23	21	4	22	20	4	20
Americas	**23**	**18**	**26**	**21**	**18**	**25**	**25**	**25**	**30**
Mexico	16	9	18	9	8	11	8	8	10
United States	7	9	8	12	10	14	17	17	20
Australia and Oceania		**8**	**1**		**5**	**1**		**14**	**3**
Australia		8	1		5	1		14	3
	212	**1,295**	**459**	**208**	**1,415**	**478**	**215**	**1,409**	**485**
Equity-accounted entities									
Algeria		27	6		21	4			
Angola	29	52	39	31	43	40	31	43	39
Mozambique		46	9		44	9		40	8
Norway	53	130	78	42	130	66	32	97	50
Tunisia	1	1	1	1	1	1	1	1	1
United Kingdom	9	38	16	2	10	4			
Venezuela	3	106	23	3	104	23	2	102	21
	95	**400**	**172**	**79**	**353**	**147**	**66**	**283**	**119**
Total	**307**	**1,695**	**631**	**287**	**1,768**	**625**	**281**	**1,692**	**604**

(a) Includes Eni's share of equity-accounted equities.
(b) Includes volumes of hydrocarbons consumed in operations (49, 49 e 46 mmboe in 2025, 2024 and 2023, respectively).
(c) Includes approximately 4 mmboe of production related to certain sanctioned joint-venture partners.

DAILY 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		2025[c]			2024			2023	
Italy	**26**	**207.7**	**65**	**27**	**196.0**	**64**	**29**	**211.2**	**69**
Rest of Europe	**1**	**66.7**	**14**	**16**	**193.5**	**53**	**18**	**108.9**	**39**
Netherlands	1	64.7	13	1	65.1	13			
United Kingdom		2.0	1	15	128.4	40	18	108.9	39
North Africa	**174**	**1,829.6**	**524**	**177**	**2,126.9**	**584**	**190**	**2,227.7**	**617**
Algeria	57	316.9	117	56	365.3	125	62	333.0	126
Egypt	62	940.6	242	59	1,145.9	279	67	1,310.0	318
Libya	54	563.8	162	60	606.7	176	59	575.4	169
Tunisia	1	8.3	3	2	9.0	4	2	9.3	4
Sub-Saharan Africa	**108**	**490.7**	**202**	**86**	**448.6**	**173**	**84**	**439.7**	**168**
Congo	24	235.7	69	26	206.8	66	36	172.9	68
Côte d'Ivoire	39	55.7	50	17	24.2	22	4	6.5	6
Ghana	13	114.4	35	12	91.1	29	14	88.4	31
Nigeria	32	84.9	48	31	126.5	56	30	171.9	63
Kazakhstan	**114**	**244.8**	**161**	**110**	**250.1**	**157**	**115**	**254.7**	**163**
Rest of Asia	**94**	**638.9**	**217**	**93**	**588.4**	**205**	**85**	**511.8**	**183**
China							1		1
Indonesia	1	475.6	92	1	500.4	97	1	407.9	79
Iraq	31	82.2	47	28	68.9	40	23	77.5	38
Timor Leste		1.4			3.0	1		8.5	2
Turkmenistan	2	61.5	14	6	6.6	7	6	6.6	7
United Arab Emirates	60	18.2	64	58	9.5	60	54	11.3	56
Americas	**62**	**47.8**	**71**	**59**	**48.7**	**68**	**68**	**69.1**	**81**
Mexico	45	23.6	49	25	20.5	29	22	23.1	26
United States	17	24.2	22	34	28.2	39	46	46.0	55
Australia and Oceania		**22.5**	**4**		**14.1**	**3**		**37.7**	**7**
Australia		22.5	4		14.1	3		37.7	7
	579	**3,548.7**	**1,258**	**568**	**3,866.3**	**1,307**	**589**	**3,860.8**	**1,327**
Equity-accounted entities									
Algeria		74.1	14		58.6	12			
Angola	79	142.2	106	86	116.4	108	85	117.4	108
Mozambique	1	125.4	25	1	120.6	24	1	109.5	22
Norway	146	356.8	214	114	354.2	181	87	265.2	138
Tunisia	2	4.0	3	2	2.8	2	2	2.8	2
United Kingdom	25	102.2	44	6	26.7	11			
Venezuela	8	290.4	64	7	285.3	62	5	279.8	58
	261	**1,095.1**	**470**	**216**	**964.6**	**400**	**180**	**774.7**	**328**
Total	**840**	**4,643.8**	**1,728**	**784**	**4,830.9**	**1,707**	**769**	**4,635.5**	**1,655**

(a) Includes Eni's share of equity-accounted equities.
(b) Includes volumes of hydrocarbons consumed in operations (134, 135 and 127 kboe/d in 2025, 2024 and 2023, respectively).
(c) Includes approximately 10 kboe/d of production related to certain sanctioned joint-venture partners.

PRODUCTIVE WELLS

In 2025, oil and gas productive wells were 6,756.0 (2,120.4 of which represented Eni's share). In particular, oil productive wells were 5,630.0 (1,637.7 of which represented Eni's share); natural gas productive wells amounted to 1.126,0 (482.7 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 and Gas (Topic 932).

PRODUCTIVE OIL AND GAS WELLS[a]

	2025			
	Oil wells		Natural gas wells	
(units)	Gross	Net	Gross	Net
Italy	**107.0**	94.8	**224.0**	193.7
Rest of Europe	**730.0**	113.5	**228.0**	54.8
North Africa	**1,916.0**	823.5	**459.0**	186.5
Sub-Saharan Africa	**1,518.0**	164.2	**134.0**	13.0
Kazakhstan	**168.0**	45.2		
Rest of Asia	**995.0**	304.2	**68.0**	25.4
Americas	**196.0**	92.3	**9.0**	5.3
Australia and Oceania			**4.0**	4.0
	5,630.0	1,637.7	**1,126.0**	482.7

(a) Includes 913 gross (240 net to Eni) 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 ACTIVITIES

Exploration

In 2025, a total of 42 new exploratory wells were drilled (16.8 of which represented Eni's share), as compared to 37 exploratory wells drilled in 2024 (15.0 of which represented Eni's share) and 39 exploratory wells drilled in 2023 (21.6 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 and Gas (Topic 932). The overall commercial success rate was 37.9% (42.2% net to Eni) as compared to 12.5% (12.8% net to Eni) and 34.5% (38% net to Eni) in 2024 and 2023, respectively.

EXPLORATORY WELL ACTIVITY

	Net wells completed[a]						Wells in progress at Dec. 31[b]	
	2025		2024		2023		2025	
(units)	productive	dry[c]	productive	dry[c]	productive	dry[c]	gross	net
Italy							**1.0**	**0.6**
Rest of Europe	**0.9**	**2.3**		1.9	0.1	0.4	**70.0**	**18.6**
North Africa	**0.8**	**2.3**	1.5	4.6	5.0	6.2	**16.0**	**10.7**
Sub-Saharan Africa		**0.2**	0.1		0.3	0.9	**43.0**	**21.0**
Kazakhstan				1.0				
Rest of Asia	**1.8**			3.5	0.9	1.3	**9.0**	**6.5**
Americas						1.4	**7.0**	**4.6**
Australia and Oceania							**1.0**	**0.3**
	3.5	**4.8**	**1.6**	**11.0**	**6.3**	**10.2**	**147.0**	**62.3**

(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 2025, a total of 303 development wells were drilled (79.1 of which represented Eni's share) as compared to 217 development wells drilled in 2024 (57.3 of which represented Eni's share) and 165 development wells drilled in 2023 (83.6 of which represented Eni's share).The drilling of 184 development wells (36.5 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 and Gas (Topic 932).

DEVELOPMENT WELL ACTIVITY

	Net wells completed[a]						Wells in progress at Dec. 31	
	2025		2024		2023		2025	
(units)	productive	dry[b]	productive	dry[b]	productive	dry[b]	gross	net
Italy			1.2		1.0		1.0	0.5
Rest of Europe	19.3		3.8		4.8		15.0	2.4
North Africa	23.8		21.3	0.5	39.4		14.0	4.9
Sub-Saharan Africa	8.7	0.1	9.2	0.5	5.6		61.0	11.9
Kazakhstan	1.8		1.2		2.0		2.0	0.6
Rest of Asia	18.4		13.4		22.9		90.0	16.2
Americas	6.0		6.2		6.9		1.0	
Australia and Oceania	1.0				1.0			
	79.0	0.1	56.3	1.0	83.6	0.0	184.0	36.5

(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 2025, Eni performed its operations in thirty-three countries located in five continents. As of December 31, 2025, Eni's mineral right portfolio consisted of 868 exclusive or shared rights of exploration and development oil and gas activities. Total acreage amounts to 205,562 square kilometers net to Eni (total acreage was 211,347 square kilometers net to Eni as of December 31, 2024). Developed acreage was 25,712 square kilometers and undeveloped acreage was 179,850 square kilometers net to Eni.

In 2025 new leases were purchased or awarded in Algeria, Egypt, Italy, Côte d'Ivoire, Norway and Tunisia for a total increase in acreage of approximately 21,200 square kilometers. Relinquishment for the year related mainly to China, Congo, Cyprus, Egypt, Mozambique, Norway, Timor Leste, the United Arab Emirates and Vietnam covering an acreage of approximately 21,250 square kilometers. Interest increases were reported mainly in Indonesia, Italy, Tunisia and the United Kingdom for a total acreage of approximately 350 square kilometers. Partial relinquishment was reported mainly in Côte d'Ivoire, Egypt, Indonesia, Italy, Timor Leste, the United Arab Emirates and the United Kingdom for approximately 6,085 square kilometers.

The gross undeveloped acreages that will expire in the next three years are related to exploration leases, blocks, concessions in: (i) Rest of Europe, in particular in Cyprus, Albania, Netherlands, Norway and the United Kingdom; (ii) Rest of Asia, in particular in Indonesia, Timor Leste, Vietnam, Lebanon, Oman and the United Arab Emirates; (iii) North Africa, in particular in Egypt and Libya; (iv) Sub-Saharan Africa, in particular in Angola, Namibia, Congo, Ghana and Côte d'Ivoire; (v) Americas, in particular in Mexico; and (vi) Australia and Oceania, in particular in Australia. In most cases extension or renewal options are contractually defined and may or may not be exercised depending on the results of the studies and the planned activities. Management believes that a significant amount of acreage will be maintained following extension or renewal.

OIL AND NATURAL GAS INTERESTS

	December 31, 2024	December 31, 2025						
	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	**38,752**	**480**	**18,026**	**59,109**	**77,135**	**8,557**	**23,062**	**31,619**
Italy	**7,797**	**108**	**7,134**	**3,404**	**10,538**	**5,938**	**2,900**	**8,838**
Rest of Europe	**30,955**	**372**	**10,892**	**55,705**	**66,597**	**2,619**	**20,162**	**22,781**
Albania	587	1		477	477		477	477
Cyprus	13,988	4		14,020	14,020		7,466	7,466
Netherlands	1,599	35	1,960	2,177	4,137	833	681	1,514
Norway	10,174	188	5,907	32,289	38,196	959	8,187	9,146
United Kingdom	4,607	144	3,025	6,742	9,767	827	3,351	4,178
AFRICA	**73,926**	**284**	**44,877**	**231,695**	**276,572**	**12,110**	**76,478**	**88,588**
North Africa	**45,131**	**157**	**20,214**	**161,671**	**181,885**	**8,143**	**52,365**	**60,508**
Algeria	8,095	78	10,858	48,717	59,575	4,240	17,069	21,309
Egypt	10,205	54	4,433	32,053	36,486	1,594	10,855	12,449
Libya	24,644	14	1,963	78,085	80,048	958	23,686	24,644
Tunisia	2,187	11	2,960	2,816	5,776	1,351	755	2,106
Sub-Saharan Africa	**28,795**	**127**	**24,663**	**70,024**	**94,687**	**3,967**	**24,113**	**28,080**
Angola	9,456	69	10,688	40,202	50,890	906	8,515	9,421
Congo	1,099	11	518	1,320	1,838	265	713	978
Côte d'Ivoire	9,007	12	1,309	11,874	13,183	676	10,084	10,760
Ghana	502	4	226	946	1,172	100	402	502
Mozambique	3,260	6	719	3,193	3,912	180	736	916
Namibia	1,145	1		5,386	5,386		1,145	1,145
Nigeria	4,327	24	11,203	7,103	18,306	1,840	2,518	4,358
ASIA	**80,904**	**36**	**14,595**	**129,039**	**143,634**	**3,832**	**63,772**	**67,604**
Kazakhstan	**1,273**	**6**	**2,391**	**2,505**	**4,896**	**442**	**831**	**1,273**
Rest of Asia	**79,631**	**30**	**12,204**	**126,534**	**138,738**	**3,390**	**62,941**	**66,331**
China	7							
Indonesia	12,051	10	2,288	14,850	17,138	1,926	9,945	11,871
Iraq	446	1	1,074		1,074	446		446
Lebanon	610	1		1,742	1,742		610	610
Oman	9,037	2		11,256	11,256		9,037	9,037
Qatar	38	1		1,206	1,206		38	38
Timor Leste	4,140	2	83	4,032	4,115	33	3,528	3,561
Turkmenistan	180	1	200		200	180		180
United Arab Emirates	16,658	7	8,559	12,032	20,591	805	8,335	9,140
Vietnam	15,245	2		12,886	12,886		10,229	10,229
Other Countries[c]	21,219	3		68,530	68,530		21,219	21,219
AMERICAS	**8,336**	**60**	**1,923**	**11,549**	**13,472**	**885**	**7,437**	**8,322**
Mexico	3,336	10	67	5,165	5,232	67	3,269	3,336
United States	362	39	595	154	749	321	27	348
Venezuela	1,066	6	1,261	1,544	2,805	497	569	1,066
Other Countries	3,572	5		4,686	4,686		3,572	3,572
AUSTRALIA AND OCEANIA	**9,429**	**8**	**328**	**15,394**	**15,722**	**328**	**9,101**	**9,429**
Australia	9,429	8	328	15,394	15,722	328	9,101	9,429
Total	**211,347**	**868**	**79,749**	**446,786**	**526,535**	**25,712**	**179,850**	**205,562**

(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.
(c) Includes exploration licenses in Russia that are expected to be relinquished.

MAIN PRODUCING ASSETS (GROUP SHARE IN %) AND THE YEAR IN WHICH ENI STARTED OPERATIONS

The table below sets forth, as of December 31, 2025 and by main producing countries in each geographic area, Eni's producing assets, the year in which Eni's activities started (for acquired assets, the year corresponds to the acquisition date) and the Eni's participating interest in each asset. The table does not include the assets held by the joint ventures and associates. In particular: (i) in Angola, the Azule Energy joint venture (Eni's interest 50%) holds interests in 17 blocks (of which 9 exploration blocks) and also in the Angola LNG JV and one exploration license in Namibia; (ii) in the United Kingdom, the Ithaca Energy joint venture (Eni's interest 35,92%) holds interests in 39 fields, of which 10 operated and production fields, located in the North Sea; (iii) in Norway, the Vår Energi associate (Eni's interest 63.1%) holds interests in 190 licences; (iv) in Mozambique, the Mozambique Rovuma Venture SpA joint venture (Eni's interest 35.71%) is the operator of the Area 4 production licence; (v) in Venezuela, where the Cardon IV (Eni's interest 50%), PetroSucre (Eni's interest 26%) and PetroJunin (Eni's interest 40%) joint ventures holds interests in the Perla, Corocoro and Junin 5 production fields, respectively; (vi) in Tunisia, where operate the Société Italo Tunisienne d'Exploitation Pétrolière (Eni's interest 50%) joint venture; and (vii) in Algeria, where operate the E&E Algeria Touat BV joint venture (Eni's interest 66%).

ITALY (1926)		Adriatic and Ionian Sea	Cervia-Arianna (100%), Luna (100%), Barbara (100%), Emilio-Donata (100%), Clara NW (51%) and Hera Lacinia (100%)
		Basilicata Region	Val d'Agri (61%)
		Sicily	Argo-Cassiopea (60%), Gela (100%), Giaurone (100%), Prezioso (100%) and Armatella (100%)
REST OF EUROPE	Netherlands (2024)		F3 (58.96%), G-blocks (from 33.7% to 60%), K2b-A (56.62%), K9ab-B (35.43%), L12-L15 (from 30% to 30.23%), L10/K12 (from 15.56% to 49.29%), L5 hub (from 59.50% to 60%), Q13a-A (50%) and K6-D (5.78%)
NORTH AFRICA	Algeria[a] (1981)		Sif Fatima II (49%), Berkine South (75%), Block 404-208 (17,5%), Zemlet El Arbi (49%), Ourhoud II (49%), Blocks 403a/d (100%), Block ROM North (35%), Blocks 401a/402a (100%), Block 403 (50%), Block 405b (75%), In Amenas (45.89%) and In Salah (33.15%)
	Egypt[a][b] (1954)		Sinai (Abu Madi, Sinai 12 Leases - 100%), Ras el Barr (Ha'py and Seth - 50%), South Ghara (South Ghara, Hilal, Shoab Ali - 25%), Alam El Shawish (Assil, Karam, Barq-Bahga, Magd - 25%), Shorouk (Zohr - 50%), Nile Delta (Abu Madi West/Nidoco, El Qar'NE - 75%), Meleiha (76%), North Port Said (Port Fouad - 100%), Temsah (Tuna, Temsah e Denise - 50%), Southwest Meleiha (SWM, SWM-4 - 75%), Baltim (Baltim North, Baltim East, Baltim South - 50%), North El Hammad Offshore (Bashrush - 37,5%) ed East Obayed (Faramid - 75%)
	Libya[a] (1959)	Offshore contract areas	Area C (Bouri - 50%) and Area D (Blocco NC 41 - 50%)
		Onshore contract areas	Area A (former concession 82 - 50%), Area B (former concession 100/ Bu-Attifel and Block NC 125 - 50%), Area E (El-Feel - 33.3%) and Area D (Block NC 169 - 50%)
	Tunisia (1961)		Adam (30%), Oued Zar (50%) and Djebel Grouz (50%)
SUB-SAHARAN AFRICA	Congo (1968)		Néné-Banga Marine and Litchendjili (Block Marine XII, 65%), Kitina (52%) and Yanga Sendji (29.75%)
	Côte d'Ivoire (2015)		Baleine (47.25%)
	Ghana (2009)		Offshore Cape Three Points (44.44%)
	Nigeria[c] (1962)		OML 125 (100%) and OML 118 (15%)
KAZAKHSTAN[a] (1992)			Kashagan (16.81%) and Karachaganak (29.25%)
REST OF ASIA	Indonesia (2001)		Jangkrik (88.33%), Jangkrik North East (88.33%) Merakes (85%) and Merakes East (85%)
	Iraq (2009)		Zubair (41.56%)[d]
	United Arab Emirates (2018)		Lower Zakum (5%), Umm Shaif and Nasr (10%) and Area B - Sharjah (50%)
	Turkmenistan (2008)		Burun (90%)
AMERICAS	Mexico (2019)		Area 1 (100%)
	United States (1968)		Allegheny (100%), Appaloosa (100%), Pegasus (100%), Longhorn (75%), Devils Towers (100%), Triton (100%), Europa (32%), Medusa (25%), Lucius (14.45%), Frontrunner (37.5%) and Heidelberg (12.5%).

(a) In certain extractive initiatives, Eni and the host Country agree to assign the operatorship of a given initiative to an incorporated joint venture, a so-called operating company. The operating company in its capacity as the operator is responsible of managing extractive operations. Those operating companies are not controlled by Eni.
(b) Eni's working interests (and not participating interests) are reported. This includes Eni's share of costs incurred on behalf of the first party accordingly to the terms of PSAs inforce in the Country.
(c) As partners of Renaissance Africa Energy Company Limited JV (RAEC JV; ex SPDC JV), Eni holds a 5% interest in 18 blocks.
(d) Eni is leading a consortium of partners including Kogas and the national oil companies Missan Oil and Basra Oil within a Technical Service Contract as contractor.

MAIN EXPLORATION AND DEVELOPMENT PROJECT

Eni's exploration and production activities are conducted in many Countries and are therefore subject to a broad range of legislation and regulations. These cover virtually all aspects of exploration and production activities, including matters such as license acquisition, production rates, royalties, pricing, environmental protection, export, taxes and foreign exchange. The terms and condition of the leases, licenses and contracts under which these Oil & Gas interests are held vary from Country to Country. These leases, licenses and contracts are generally granted by or entered into with a government entity or state company and are sometimes entered into with private property owners. These contractual arrangements usually take the form of concession agreements or production sharing agreements.

Concessions contracts. Eni operates under concession contracts mainly in Western Countries. Concessions contracts regulate relationships between States and oil companies with regards to hydrocarbon exploration and production activity. Contractual clauses governing mineral concessions, licenses and exploration permits regulate the access of Eni to hydrocarbon reserves. The company holding the mining concession has an exclusive right on exploration, development and production activities, sustaining all the operational risks and costs related to the exploration and development activities, and it is entitled to the productions realized. As a compensation for mineral concessions, pays royalties on production (which may be in cash or in-kind) and taxes on oil revenues to the state in accordance with local tax legislation. Both exploration and production licenses are granted generally for a specified period of time (except for production licenses in the United States which remain in effect until production ceases): the term of Eni's licenses and the extent to which these licenses may be renewed vary by area. Proved reserves to which Eni is entitled are determined by applying Eni's share of production to total proved reserves of the contractual area, in respect of the duration of the relevant mineral right.

Production Sharing Agreement (PSA). Eni operates under PSA in several of the foreign jurisdictions mainly in African, Middle Eastern, Far Eastern Countries. The mineral right is awarded to the national oil company jointly with the foreign oil company that has an exclusive right to perform exploration, development and production activities and can enter into agreements with other local or international entities. In this type of contract, the national oil company assigns to the international contractor the task of performing exploration and production with the contractor's equipment (technologies) and financial resources. Exploration risks are borne by the contractor and production is divided into two portions: "Cost Oil" is used to recover costs borne by the contractor and "Profit Oil" is divided between the contractor and the national company according to variable schemes and represents the profit deriving from exploration and production. Further terms and conditions of these contracts may vary from Country to Country. Pursuant to these contracts, Eni is entitled to a portion of a field's reserves, the sale of which is intended to cover expenditures incurred by the Company to develop and operate the field. The Company's share of production volumes and reserves representing the Profit Oil includes the share of hydrocarbons which corresponds to the taxes to be paid, according to the contractual agreement, by the national government on behalf of the Company. As a consequence, the Company has to recognize at the same time an increase in the taxable profit, through the increase of the revenues, and a tax expense. Proved reserves to which Eni is entitled under PSAs are calculated so that the sale of production entitlements should cover expenses incurred by the Group to develop a field (Cost Oil) and recognize the Profit Oil set contractually (Profit Oil). A similar scheme applies to some service contracts.

Italy

The cancellation of the PiTESAI in 2024 brought the legislative mining right (Titoli minerari) back to the original text, allowing in 2025 the total or partial reassignment of 10 exploration permits and 3 extension applications.

In addition, in compliance with EU Regulation 2024/1787 on the methane gas emissions reduction in the energy sector, activities to quantify methane emissions were completed and reported to Italian Authority MASE (Ministero dell'Ambiente e della Sicurezza Energetica). This included fugitive emissions monitoring by means of Leak Detection and Repair type 2 for each operational site as well as for shut-in and abandoned wells.

In the gas assets of the Adriatic and Ionian Seas, activities concerned: (i) the production start-up of new wells in the Cervia Mare (the Cervia field) and Fauzia concessions; (ii) the installation of a new compressor facility in the Falconara gas treatment plant; (iii) optimizations activities at the Antonella platform; (iv) a plug-and-abandon campaign for no longer productive wells, including those for the Ravenna CCS project, is ongoing; and (v) local development initiatives, including the third edition of ORA! Outpost Ravenna for Energy Transition, with open innovation projects and programs in the health and social sectors in partnership with stakeholders and local authorities. In Marina di Ravenna, the collaboration with the Local Health Authority of Romagna area progressed to enhance primary healthcare services.

The activities of the year in the Val d'Agri Concession concerned: (i) the filing of "Variazione Programma Lavori" to the relevant authorities for the development program of the northerner part of the field; and (ii) production optimization actions to mitigate production decline. In addition activities of the New Memorandum of Intent between Eni, Shell and the Basilicata Region progressed and included "non-oil" projects for local development as well as initiatives defined with the agreement with the Basilicata Region within the LucAS (Lucani Ambiente e Salute) project.

Within the development program of the Argo Cassiopea project in the Sicilian offshore, the activities of the year concerned: (i) the completion

of the Cassiopea onshore plants; and (ii) the "Variazione Programma Lavori" for the Gemini development project have been submitted to the relevant authorities. In addition, activities have been launched to assess exploration potential of the permit nearby to the Argo Cassiopeia concession, including the Panda discovery.
Within local support initiatives: (i) the Implementation Agreement for renovation program in the Gela area was signed; (ii) the Cooperation Agreement with Banco Alimentare has been renewed, in continuity from 2023, supporting the disadvantages communities; and (iii) the "Musei in Rete - Digitalizzare I Beni Culturali" project was launched in collaboration with the Eni Enrico Mattei Foundation and local stakeholders. In addition, district upgrading, economic enhancement, educational support and environmental protection interventions were carried out in the Municipality of Crotone through Eni's voluntary contributions.

Rest of Europe

Netherlands. The activities of the year concerned: (i) the Final Investment Decision (FID) of the L7-F gas development project, production start-up is expected in 2026; (ii) the drilling of the L10-M4 development well, with production expected in 2026.

Norway. Exploration activity yielded positive results with five commercial discoveries, in particular with: (i) the Vidsyn exploration well in the PL586 license in the Norwegian Sea; (ii) the Drivis Tubåen exploration well in the PL532 license in the Barents Sea nearby to the Johan Castberg field; (iii) the Goliat Ridge discoveries, adjacent to the Goliat producing field in the Barents Sea. Evaluation activities are underway for fast-track development; (iv) the F Sør exploration well in the PL090 license in the North Sea and of the Smørbukk Midt exploration well in the PL094 license in the Norwegian Sea, the latter already in production leveraging on the existing facilities in the area.
In 2025, an additional participation stake was acquired in the Ekofisk producing project in the PL018F development license and thus Vår Energi's interest to approximately 52% in the Greater Ekofisk Area. The transaction is subject to the necessary approvals.
During 2025, production start-up was achieved at: (i) the Johan Castberg oil fields which includes the Skrugard, Havis and Drivis discoveries made between 2011 and 2014. The field will be producing for 30 years, with an expected production peak of 220 kbbl/d; (ii) the Balder-X oil field in Norwegian offshore with a peak production of about 80 kboe/d already reached during 2025; (iii) the Askeladd West gas field to ensure full capacity of the Hammerfest LNG plant in the next years.

United Kingdom. During 2025, the farm-in agreements were completed in: (i) the Seagull field with acquisition of 15% interest and in the Cygnus field with an additional stake acquisition of 46%; (ii) the Tobermory gas discovery to acquire 50% interest in the West of Shetland basin.
Development activities concerned: (i) production start-up of additional wells at the Captain, Cygnus and Seagull producing fields; (ii) production optimization activities in the J-Area project; and (iii) the development program of the Rosebank project.

North Africa

Algeria. In 2025, Eni signed a petroleum contract with Sonatrach for the exploration and development of the Zemoul El Kbar area. The contract, with a duration of 30 years, covers a development and exploration area of about 4,200 square kilometers and includes neighboring assets previously under separate contracts. This new agreement follows the recent award, in the context of 2024 Algeria Bid Round, of the Reggane II block to Eni in partnership with PTTEP.
During the year, an additional stake in the Touat license was acquired, increasing Eni's interest to 42.9%.
Development activities mainly concerned the start-up of new producing wells and production optimization activities by means of workover program and plant upgrading of existing facilities.

Egypt. Exploration activity yielded positive results in the Western Desert concessions. The discoveries were already put into production and achieving production ramp-up in the area.
In 2025 signed agreements with Cyprus and Egypt counterparties to develop gas reserves of the Block 6 offshore Cyprus, to be exported to international markets through Eni's existing facilities located in Egypt. The agreements are an important milestone on the path to the sanctioning of the project, and they foresee treatment and liquefaction through the processing plants facilities of the Zohr field and the liquefaction capacity at the Damietta LNG plant.
Development activities mainly concerned: (i) production optimization and drilling activities in the Mediterranean offshore; and (ii) ongoing construction activities of the gas plant in the Western Desert area as provided by the development plan.
In 2025, Zohr production was optimized through activities of reservoir and network management. The drilling campaign performed in 2025 was successfully executed and new optimization opportunities are under definition for 2026.
Eni holds interest in the Damietta liquefaction plant with a capacity of 5.2 mmtonnes/y of LNG associated to approximately 283 bcf/y of feed gas.

Local development initiatives concerned: (i) the University Education project in Energy Engineering Technology, carried out in collaboration with the Politecnico di Milano and Eni Corporate University in the Port Said area; (ii) in the healthcare sector, the Advanced Professional Training Center, established in collaboration with the Ministry of Health and Population (MoHP) in Port Said, provided training of local staff to fill key gaps in medical specialties and to enhance the clinical skills of healthcare staff at the national level; (iii) projects in the agricultural sector in the Governorates of South Sinai and Matrouh for communities in areas with high desertification, as well as the Towards Organic Agriculture project to support small farmers in the transition to organic farming.

Libya. In February 2026 Eni was awarded the O1 offshore exploration license through a consortium with another partners. Eni will be the operator. In 2025 development activities mainly concerned: (i) in the Sabratha Compression project to support current production of the Bahr Essalam field, offshore activities advanced with the installation of the compression unit in the Sabratha platform; (ii) the Bouri Gas Utilization Project is ongoing as provided for the development plan, with start-up expected in 2026; and (iii) the drilling activities at the A&E Structures project as well as the construction activities of the Structure A platform were started. In addition during the year: (i) the professional training project progressed in partnership with the International Organization for Migration to increase employment opportunities; (ii) a project for the preservation and promotion of cultural heritage was launched; (iii) in the healthcare sector, a program was started in the Jalo area to strength and improve the quality of services.

Tunisia. In 2025, Eni was awarded a 35% stake in the Sabeh concession.
The activities of the year mainly concerned: (i) the development activities of the Sabeh concession; (ii) a production optimization program in the Adam, MLD and El Borma concessions; (iii) the start of development drilling activities in the Djebel Grouz concession; and (iv) the program to support local development, mainly with the installation of photovoltaic panels in 14 public schools.

Sub-Saharan Africa

Angola. The exploration activity yielded positive results: (i) with the first dedicated gas exploration well, Gajajeira-01; and (ii) in February 2026, with the Algaita-01 oil well in the offshore Block 15/06.
In 2025, Azule signed a farm-out agreement to sell its 20% stake in Block 14 and 10% in Block 14K/A-IMI. The transaction is subject to approval by the relevant authorities.
In the year, production started at the Agogo Integrated West Hub project, in block 15/06, offshore Angola. The project consist in the development of two fields, Agogo and Ndungu, with an expected production plateau of 180 kboe/d. In February 2026 full-field production start-up was achieved at the Ndungu field, just six months after Agogo FPSO first oil.
The development activities concerned: (i) The NGC (New Gas Consortium) project to develop the Quiluma and Maboqueiro fields. The project, the first non-associated gas development in the country, completed the installation and commissioning of two offshore production platforms as well as the gas and condensate treatment and export plant to the A-LNG plant. The estimated production plateau is approximately 330 mmcf/d and 18 kbbl/d of condensates. First gas production into plant was reached in February '26; (ii) the Greater PAJ project to develop the southern area of the two operated blocks 31 and 31/21. The project's final approval by the partners is expected in 2026.
During 2025, programs to support local development progressed by means of certain initiatives on promoting access to water and sanitation, community health, education, social inclusion, economic diversification, access to solar energy, environmental protection and demining. In particular: (i) in the educational field, 3 new schools were opened and 10 schools were renovated; (ii) extension agreement was signed to support the cardiological care improvement in the country's healthcare facilities, as well as 2 new medical facilities were inaugurated while the renovation of 9 others was completed; (iii) international healthcare capacity building programs progressed to enhance the skills of hospital healthcare staff by means of specialized training activities in five hospitals in Luanda, involving Italian Centers of Excellence; and (iii) projects for environmental protection have been implemented.

Congo. In March 2025, Eni and Vitol agreed on the economic terms of the possible farm-out of a 25% stake held by Eni in the Congo FLNG project. The closing of the transaction is subject to customary regulatory approvals and other conditions.
During the year, Eni closed the divestment of onshore producing licenses in the country, in line with strategy of rationalizing the upstream portfolio.
It was inaugurated the new Yasika logistics platform, a strategic infrastructure within the Phase 2 development program of the Congo LNG project. The platform supports the operations for the two floating liquefaction units: Tango FLNG (0.6 mmtonnes/year), which began production in December 2023, and Nguya FLNG (2.4 mmtonnes/year), with production start-up achieved at the end of 2025, marking the completion of the Phase 2 to enhance the gas potential of the Marine XII permit and to increase the production capacity to 3 MTPA.
Within the local development initiatives: (i) the Oyo Center of Excellence for Renewable Energy and Energy Efficiency (CEO) reached full operational capacity during the year; (ii) awareness programs on the deployment of renewable energy technologies progressed to support the country's socio economic development; (iii) the integrated program in the HINDA district progressed targeting interventions for rural communities by means of education and health initiatives, access to water resources, and supporting the agricultural sector.

Côte d'Ivoire. Exploration activity yielded positive results: (i) with the drilling of the Cachalot-1X well, which confirmed the eastern extension of the Baleine field; and (ii) in February 2026, with the offshore Murene South-1X gas and condensate well in the Block CI-501 (Eni operator with a 90% interest).
Within Eni's strategy of optimizing its upstream portfolio by accelerating the monetization of exploration discoveries through the divestment of equity stakes, in September 2025 Eni finalized the sale of a 30% stake in the Baleine project to Vitol and in January 2026 Eni signed a binding agreement with SOCAR, the State Oil Company of the Republic of Azerbaijan, for the sale of an additional 10% stake in the project.
In October 2025, Eni signed an exploration contract for the CI-707 offshore block, geologically continuous with the nearby CI-205 block, where Eni announced the discovery of Calao in March 2024. This proximity offers an opportunity for future synergistic developments.
In 2025 Eni and Petroci announced a significant increase in gas supply for Côte d'Ivoire's power generation system. The gas produced, up to 70 mmcf/d, will be entirely allocated to meet local demand, ensuring a reliable supply for the country's power generation needs and further reinforcing Côte d'Ivoire's role as a regional energy hub.
The development activities of the year included: (i) the completion of the Phase 2 project at the Baleine field; and (ii) the Phase 3 concept definition activities of the Baleine development program. The final investment decision (FID) is expected to be sanctioned in 2026. The Phase 3 project provides for increasing production capacity to an expected peak of 150 kbbl/d and approximately 200 mmcf/d of associated gas for domestic needs.
In addition, within the Baleine project, local development activities concerned: (i) initiatives to support 20 healthcare centers including facilities renovation, energy infrastructure development, and medical and equipment supply; (ii) professional training programs to promote youth employment, particularly through collaboration with the Iveco Group; (iii) economic diversification, access to education, and school equipment supply initiatives.

Ghana. Exploration yielded positive results with the Eban 2A well and thus marking the close of the appraisal campaign Eban-Akoma field in the Cape Three Points 4 block with the formalization to the Government.
In September 2025, Eni and its Offshore Cape Three Points (OCTP) project partners, Vitol and the Ghana National Petroleum Corporation (GNPC), signed a Memorandum of Intent with the Government of Ghana, finalized to the country's oil and gas production increase and new sustainable initiatives. The collaboration focuses also on the evaluation of exploration activities and the new potential development of the Eban-Akoma field. In particular, the development project provides for the linkage to the existing facilities in the OCTP permit operated by Eni and was submitted for approval by the country's authorities at the end of 2025.
Development activities of the year mainly concerned the OCTP producing permit: (i) workover activities at the wells of the Sankofa East field; (ii) the debottlenecking activities of the non-associated gas system were completed and thus increasing capacity; (iii) tenders were launched for awarding contracts of the linkage of the new GyeNyame non-associated gas well to existing FPSO; (iv) the Afforestation Project progressed within environmental protection initiatives; and (v) access to water and sanitation programs as well as healthcare initiatives including community awareness campaigns, particularly in the western area of the country.

Mozambique. In October 2025, Eni and its partners reached the Final Investment Decision (FID) to develop the Coral North FLNG project which will put in production the gas volumes from the northern part of Area 4 Coral gas reservoir. In January 2026, the sail away of the Coral North floating LNG was achieved, fully in line with the project schedule, with 3.6 MTPA production capacity, bringing the country's total LNG production to 7 MTPA. The project will leverage Eni's fast-track approach and expertise from the Coral South project and is expected to achieve start-up at the end of 2028.
During the year initiatives to support local communities progressed with: (i) programs to promote schooling and youth employment in the Pemba district, as well as initiatives to improve access to drinking water in the districts of Pemba, Mecufi, and Metuge; (ii) activities to enhance social and health services, also by means of training programs. In particular, a new Intensive Care unit and a CT scanner were put into operation in the Cabo Delgado Province, and renovation activities progressed with on two maternity wards and facilities providing accommodation for pregnant women, and three ambulances were supplied in the Maputo Province; and (iii) economic development programs in the agricultural and fisheries sectors in the provinces of Cabo Delgado and Manica, as well as biodiversity protection initiatives in the Mecufi district.

Namibia. Exploration activity yielded positive results with the Sagittarius-1X gas and condensate well, the Capricornus-1X oil well as well as a further rich gas and condensate discovery at Volans-1X well. The appraisal campaigns planned in the Capricornus area and results of the production tests will be evaluated for possible integrated development projects.

Nigeria. In November 2025, Eni acquired an additional 2.5% stake in the Production Sharing Contract (PSC) OML 118, exercising its pre-emption right.
In March 2026, signed an agreement between the Federal Government of Nigeria and Eni on the conversion of Oil Prospecting Licence 245 (OPL 245). The agreement includes the mutually satisfactory settlement of all claims related to OPL 245 and the discontinuation of the international arbitration proceeding; as a consequence, it allows the conversion of the existing license into two development licences, Petroleum

Mining Leases (PML) 102 and 103, and two exploration licences, Petroleum Prospecting Leases (PPL) 2011 and 2012, to Nigerian Agip Exploration Limited (NAE) as operator, alongside its partners Nigerian National Petroleum Company Limited (NNPC) and Shell Nigeria Exploration and Production Company Limited (SNEPCO).
The development activities of the year concerned the Bonga North project in the OML 118 block, which includes the linkage of new subsea wells to the existing FPSO.
Eni holds a 10.4% stake in Nigeria LNG Ltd, which owns and runs the Bonny natural gas liquefaction plant in the Eastern Niger Delta. The plant has a production capacity of 22 mmtonnes/y of LNG associated, corresponding to approximately 1,270 bcf/y of feed gas. The natural gas supplies to the plant are currently provided under a gas supply agreement from the RAEC JV (ex SPDC JV), TEPNG JV and Oando Energy Resources Nigeria Limited JV. The volumes treated by the plant during 2025 amounted to approximately 830 BCF. LNG production is sold under long-term contracts in the United States, Asian and European markets by the Bonny Gas Transport fleet, wholly owned by Nigeria LNG Ltd as well as is sold FOB by means of the fleet owned by third parties.

Kazakhstan

Kashagan. Development plans envisage a phased increase in the production capacity. The first development phase provides for a progressive increase up to 450 kbbl/d. The activities, sanctioned in 2020, include the upgrading of management capacity of associated gas by means of: (i) increasing gas reinjection capacity by upgrading existing facilities, which was completed in 2022; and (ii) installation of a new onshore treatment unit operated by a third party, currently under construction, for the remaining part of associated gas volumes.
In 2025, production averaged 84 kboe/d net to Eni.

Karachaganak. In 2025 activities progressed with the installation of a sixth compression unit, last development phase, sanctioned in 2022. Start-up is expected in 2026. Local development initiatives included: (i) the construction and opening of a collection and processing center for agricultural products in Aksai; (ii) the project definition for the prevention and mitigation of natural disaster impacts, with implementation expected to begin in 2026; (iii) technical training programs.

Rest of Asia

Indonesia. Exploration activities yielded positive results with: (i) the Konta-1 well in the Muara Bakau block with a significant gas and condensates discovery where a production test has been successfully performed. This discovery is nearby existing facilities of the Jangkrik production field, providing significant synergies for the development; and (ii) the Kadal-1 gas well in the East Ganal block (Eni's interest 100%), with an option for a development program in synergy with the Maha project.
In November 2025 Eni signed an investment agreement with Petronas, Malaysian state-owned company, to establish a jointly controlled venture to combine the two partners' gas-rich production and development assets of Indonesia and Malaysia. The new company will be financially self-sufficient entity and able to generate operational and financial synergies to deliver one of the main players on the LNG market and plans to grow to 500 kboe/d of production in the medium term. The transaction completion is subject to governmental, regulatory, and partner approval.
In May 2025, gas production start-up was achieved at the Merakes East field, in East Sepinggan block (Eni operator with an 85% interest) in the Kutei basin, offshore Indonesia, with initial rate of approximately 18 kboe/d to Eni's production.
In the year development activities concerned: (i) the definition of integrated project of the Geng North and Gehem fields within the Northern Hub development, in the Kutei area. These fields will be put into production by means of subsea wells, flowlines and a new FPSO. Natural gas will be treated by the FPSO and will be carried to onshore facilities linked to the East Kalimantan pipeline network. The production will be delivered to the Bontang LNG plant and exported; a part of gas production will be destined to fulfil domestic needs. The condensates production will be stabilized and stored by the FPSO and then lifted; (ii) the definition of the Gendalo & Gandang project. The development program of two fields provides for the drilling of new subsea wells and the tie-back connection to existing facilities of the Jangkrik production fields; (iii) the execution of the Maha project where two new subsea wells will be put into production by means of tie-back connection to existing facility of Jangkrik field; (iv) projects supporting local communities in the primary education, access to water and renewable energy areas, and economic diversification and training activities in the Samboja and Muara Jawa areas in the Easter Kalimantan; and (v) community health initiatives, including the sanitation facilities renovation, first aid training courses, support for an infectious disease ward development, and the medical equipment supply.

Iraq. Activities comprised the execution of an additional development phase of the ERP (Enhanced Redevelopment Plan) at the Zubair field. Main facilities have already been installed. Ongoing development activities include programs to expand water availability to maintain adequate reservoir pressurization in the long-term and to increase water treatment and re-injection capacity. In particular, at the end of 2025 it has been initiated the phased start-up of the Zubair Mishrif Expansion project. This project includes four oil treatment units for a total capacity of 200 kboe/d to ensure the replacement of existing production facilities and an additional water injection capacity of 750 kboe/d. In addition, a program to achieve technical zero flaring by 2027 is being implemented.

The field reserves will be progressively put into production by drilling additional productive wells over the next few years and by means of the collection facilities expansion and the completion of the water reinjection wells.
During the year, Eni continued its commitment to local development through projects in the areas of education, healthcare and access to water. In particular: (i) the second development phase of the Al-Buradeiah plant to supply drinking water was completed in Basra; and (ii) the construction start-up of two school buildings in Zubair.

Turkmenistan. Development activities mainly concerned: (i) the drilling of nine infilling and periphal wells; and (ii) the conversion of five wells to water injectors to maximize hydrocarbon recovery.

United Arab Emirates. In June 2025, the new Production Concession license of the offshore Block 2 to develop the Waset field (Eni's interest 28%) was approved by the country's Authority.
Activities of the year mainly concerned: (i) the development program of the Ghasha offshore concession (Eni's interest 10%) to put into production the Dalma, Hail and Ghasha fields. In particular, the Dalma Gas project is being finalized while activities progressed at the Hail & Gasha project, sanctioned in 2023, according to the development plan; and (ii) ongoing development activities to support the increasing production at the Lower Zakum and Uum Shaif/Nasr concessions.

Americas

Mexico. In 2025 Eni started the relinquishment of the Area 14 and Area 28 licenses in line with strategy of rationalizing the upstream exploration portfolio. Formalization process by the relevant Authorities is ongoing.
Development activities of the Area 1 producing project concerned: (i) the drilling of five development wells; and (ii) ongoing infilling program to optimize hydrocarbons recovery.
Within the collaboration agreements with national authorities, initiatives supporting local communities progressed with agricultural, fisheries and healthcare programs, including environmental and social awareness campaigns.

United States. Activities of the year concerned production optimization at the Devil's Tower operated field and at the Lucius and Europa non-operated fields.

Venezuela. The political and economic crisis in Venezuela continued for years, influenced by the sanctions imposed by the US on exports crude oil targeting the Venezuelan government and the State oil Company PDVSA. Eni's activities in the Country include the Perla offshore gas field, operated by the local joint venture Cardón IV SA, equally participated by Eni and other international oil company, where equity volumes of natural gas supplied to the national oil company of Venezuela. Other petroleum interests held by Eni in the Country comprise oil licenses in the Orinoco Belt, operated under the "Empresa Mixta" regime, where production is declining and their carrying amounts were fully impaired in prior years. Eni is exposed to credit exposure to recover its investment in Cardón IV due to the financial difficulties of PDVSA following the U.S. sanctions regime in force through 2025. (for further information see "Risk factors and uncertainties" and "Notes on Consolidated Financial Statements"). However, in early 2026 certain developments were recorded in the relations between Venezuela and the United States, which are expected to improve the outlook for the country's oil sector. These developments could, compared with the past, partially mitigate the uncertainty of the operating environment in relation to the recovery of Eni's trade receivables from the state-owned oil company PDVSA and may give rise to potential business opportunities, subject to the evolution of the relevant regulatory and operating conditions. At the end of January 2026, the National Assembly approved a partial reform of the Organic Hydrocarbons Law which includes the renegotiation of existing oil contracts in relation to the Empresa Mixta regime, a new taxation system, and the proposal to strengthen legal safeguards for investment by introducing the possibility of resorting to independent mediation and arbitration mechanisms. In addition, the USA Authority issued "general licenses" enabling operations in the oil and gas sector in Venezuela by certain U.S. and European oil companies. Particularly significant is General License 50A, which broadly authorizes Eni to carry out transactions in the oil and gas sector in Venezuela that would otherwise be prohibited under the Venezuelan sanctions program (including those involving the Government of Venezuela, PDVSA, and its subsidiaries). These developments enhance the credit recovery outlook compared to the early scenario characterized by the US sanction regime on Venezuelan oil and gas sector.

Australia and Oceania

Australia. Activities for the year concerned engineering studies for the development program of the Petrel field (Eni's interest 100%, following acquisition of stake held by third parties closed in December 2025) located in the WA-6-R and NT/RL1 offshore blocks near to the Blacktip facilities where it will be linked. The project includes the drilling of two wells, the construction and installation of a platform and natural gas transport facility.