February 16, 2026

Alessandro Tiani
Head of Reserves

Eni S.p.A
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Attn: Mr. Alessandro Tiani, Head of Reserves

Sproule International Limited ("Sproule ERCE") has been engaged by Eni S.p.A. ("ENI" or the "Company") to evaluate the Proved reserves in Asia and the Americas, as of December 31, 2025, and to prepare a report as to its findings (the "Report"). This evaluation was completed on February 3, 2026. ENI has represented that these properties account for 9 percent of ENI's net proved reserves as of December 31, 2025, on an oil equivalent barrel basis.

The net proved reserves estimates were prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the United States Securities and Exchange Commission (SEC). It is our opinion that the procedures and methodologies employed by ENI for the preparation of its proved reserves estimates as of December 31, 2025, comply with the current requirements of the SEC. We have reviewed information provided by ENI that it represents to be ENI's estimates of the net reserves, as of December 31, 2025, for the same properties as those which we evaluated. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by ENI.

Reserves estimates presented in this certification letter are expressed as net reserves as represented by Eni. Gross reserves are defined as the total estimated hydrocarbon remaining to be produced from these properties after December 31, 2025. Net reserves are defined as the portion of gross reserves attributable to the interests held by ENI after the deduction of royalties. The accuracy of reserves estimates and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. Given the data provided at the time this report was prepared, the estimates presented herein are considered reasonable.

Information used in the preparation of this certification letter was obtained from ENI. In the preparation of this certification letter we have relied upon information furnished by ENI with respect to the evaluated property interests and burdens, production from such properties, relevant production and analytical tests performed in such properties, relevant geoscience data such as logs and analytical reports, current costs of operation and development, future capital costs for development, future costs for abandonment and reclamation in compliance with local abandonment and reclamation requirements, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented.

In the preparation of this evaluation, field inspections of the properties were not performed. No material information regarding the reserves evaluation would have been obtained by an on-site visit.

Definitions of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as below (from Regulation S-X):

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible - from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations - prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

i. The area of the reservoir considered as proved includes:

   a. The area identified by drilling and limited by fluid contacts, if any, and

   b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

ii. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

iii. Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

iv. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

   a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

   b. The project has been approved for development by all necessary parties and entities, including governmental entities.

v. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed Oil and Gas Reserves

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

i. Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

ii. Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped Oil and Gas Reserves

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

i. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

ii. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years unless the specific circumstances justify a longer time.

iii. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019” and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by ENI, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved. The undeveloped reserves estimated herein were based on opportunities identified in the development plan provided by ENI.

ENI has represented that its senior management is committed to the development plan provided by ENI and that ENI has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

The technically recoverable oil and natural gas resources were estimated volumetrically, using analogy techniques, or by decline analysis. Volumetric reserves were estimated using the geological models constructed by ENI using a commercial geomodel software. Reservoir rock and fluid property data were obtained from well logs, PVT data and gas analyses either from the pool in question or from a similar reservoir producing from the same zone. Reservoir pressures were derived from drillstem and AOF test data and pressure surveys. Recovery factors for technically recoverable resources were selected from the results of analytical reservoir analyses, or by comparing the reservoir under study with similar reservoirs that have more firmly established recovery factors from extended production histories.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP and OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. In all cases, reserves were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available and provided by ENI. When applicable, material balance and other engineering methods were used to estimate recovery factors based on an analysis of reservoir performance, including production rate, reservoir pressure, and reservoir fluid properties.

Oil and condensate reserves estimated herein are to be recovered by normal field separation. Plant liquids volumes estimated herein include propane, butane, and pentanes and heavier fractions (C5+). Plant liquids volumes are the result of low-temperature plant processing.

Oil, condensate, and plant liquids volumes reported herein are expressed in thousands of barrels (10^3 bbl). Gas quantities estimated herein are expressed as natural gas, sales gas, and dry gas. Natural gas is the total gas produced from the reservoirs prior to processing or separation and includes all nonhydrocarbon components.

Sales gas is defined as the total gas to be produced from the reservoirs, measured at the inlet of the processing plant, after reduction for injection, fuel usage, flare, and shrinkage resulting from field separation. Dry gas is defined as the total gas to be produced from the reservoirs, measured at the tailgate of the processing plant, after reduction for injection, fuel usage, flare, and shrinkage resulting from field separation and plant processing. Gas reserves estimated herein are reported as sales gas.

Gas quantities estimated herein are expressed at a temperature base of 20 degrees Celsius (°C) and at a pressure base of 1 atmosphere (atm). Gas quantities presented in this certification letter are expressed in millions of cubic metres ($10^6 m^3$). Gas quantities are identified by the type of reservoir from which the gas will be produced. Non-associated gas is gas at initial reservoir conditions with no crude oil present in the reservoir.

Associated gas includes both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying crude oil zone. Solution gas is gas dissolved in crude oil at initial reservoir conditions. Gas quantities estimated herein include both associated and Non associated gas.

At the request of ENI, gas quantities estimated herein were converted to dry gas equivalent to liquids using an energy equivalent factor as provided by ENI.

ENI has represented that the development activities provided and evaluated herein were internally approved.

Development activities provided by ENI are scheduled to initiate within 5 years of the effective date of the Report (December 31, 2025) for activities associated with Proved undeveloped reserves.

The oil and natural gas reserves were estimated based on the technically recoverable resources, operating and capital costs and the terms of the fiscal regime. Forecasts of net revenue were prepared by predicting the annual production from the reserves, and ENI provided product prices.

The technically recoverable condensate resources were estimated based on estimates of future gas production and future condensate recovery provided by ENI. Annual production was forecast taking into account well deliverability, the status of reservoir depletion, applicable regulatory conditions, and by comparison with other wells in the vicinity producing from similar reservoirs when available.

Gas reserves have been assigned based on confirmation from ENI that there is a market to produce to. The expense has been included in the cash flows for the use of fuel gas.

Solution gas reserves have been assigned based on confirmation from ENI that there is a market to produce for. The expenses for the use of fuel gas have been included in the costs provided by ENI.

The price forecasts that formed the basis for the revenue projections in the evaluation were based on the constant prices provided by ENI at December 31, 2025.

Primary Economic Assumptions

This report has been prepared using initial prices, expenses, and costs provided by ENI in United States Dollars ($). Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the reserves reported herein:

Product Prices

ENI has represented that the oil, condensate and gas prices were based on a reference price, 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, unless prices are defined by contractual agreements. The prices were not escalated for inflation.

Location	Oil	Condensate	Sales Gas
	USD/bbl	USD/bbl	USD/10^3m^3
Americas	66.30	-	156.50
Asia	63.30	58.70	340.20

Operating Expenses, Capital Costs, and Abandonment Costs

The operating costs and capital costs used in the evaluation were provided by ENI. Estimates of operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of the developed non-producing and the undeveloped reserves estimated herein.

The abandonment, decommissioning and reclamation ("ADR") costs associated with ENI's hydrocarbon exploration, development, production and processing operations in the property of interest were included in this report. ENI provided estimates of the ADR costs associated with their hydrocarbon exploration, development, production and processing operations, for inclusion in this evaluation of their hydrocarbon assets data and were accepted as represented.

Guidance

In our opinion, the information relating to estimated proved reserves of oil, condensate, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, and 932-235-50-9 of the Accounting Standards Update 932-235-50, Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures (January 2010) of the FASB and Rules 4–10(a)(1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the SEC.

Summary of Conclusions

ENI has represented that its estimated net Proved reserves attributable to the evaluated properties were based on the definition of proved reserves of the SEC.

In comparing the detailed net Proved reserves estimates prepared by Sproule ERCE and ENI, differences have been found, both positive and negative, resulting in an aggregate difference within 5 percent for Proved reserves when compared on the basis of net oil equivalent barrels. It is Sproule ERCE opinion that the net Proved reserves estimates prepared by ENI on the properties evaluated and referred to above, when compared on the basis of net equivalent barrels, in aggregate, are reasonable.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2025 estimated reserves.

Sproule ERCE possesses the technical skills and certifications required for this type of work. Sproule ERCE is a member in good standing of the Association of Professional Engineers and Geoscientists of Alberta ("APEGA"), an independent regulatory body that governs the practice of engineering and geoscience in the province of Alberta, Canada.

Sproule ERCE is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1951. Sproule ERCE does not have interest, direct or indirect, nor expects to receive any interest, direct or indirect, in the properties described in the report or in the securities of ENI. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of ENI. Sproule ERCE has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Yours faithfully,

Sproule International Limited

Feb. 16, 2026

Doug Ashton, P.Eng.

Vice President, Americas, Subsurface Advisory

Sproule ERCE

Certificate of Qualification

Doug Ashton, P.Eng.

I, Doug Ashton, Vice President, Americas, Subsurface Advisory of Sproule ERCE, 900, 140 Fourth Avenue SW, Calgary, Alberta, declare the following:

1. I hold the following degree:
    a. B.Sc. Chemical Engineering (1992), University of Calgary, Calgary, AB, Canada
2. I am a registered Professional:
    a. Professional Engineer (P.Eng.), Province of Alberta, Canada
3. I am a member of the following professional organizations:
    a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
    b. Society of Petroleum Evaluation Engineers (SPEE)
    c. Society of Petroleum Engineers (SPE)
4. I am a qualified reserves evaluator and reserves auditor as defined in:
    a. the “Canadian Oil and Gas Evaluation Handbook” as promulgated by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and,
    b. the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” as promulgated by the Society of Petroleum Engineers and incorporated into the “Petroleum Resource Management System” (SPE-PRMS).
5. My contribution to the work related to the attached third party letter is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule ERCE.
6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of ENI S.p.A.

Feb. 17. 2026

Doug Ashton, P.Eng.

Locations

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