DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

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DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 16, 2026

Mr. Alessandro Tiani
Head of Reserves
Eni S.p.A.
Via Emilia 1
20097 San Donato Milanese
Italia

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2025, of the extent of the estimated net proved oil, condensate, liquefied petroleum gas (LPG), and gas reserves of certain properties in which Eni S.p.A. (Eni) has represented it holds an interest through its 63.04-percent corporate ownership of Vår Energi ASA. This evaluation was completed on February 16, 2026. The properties evaluated herein consist of fields located offshore Norway (Table 1). Eni has represented that these properties account for 7.9 percent on a net equivalent barrel basis of Eni's net proved reserves as of December 31, 2025. The net proved reserves estimates have been 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). 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 estimated herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2025. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Eni after deducting all interests held by others.

Estimates of reserves should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such

estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was provided by or on behalf of Eni. In the preparation of this report we have relied, without independent verification, upon information furnished by or on behalf of Eni with respect to the property interests being evaluated, production from such properties, current costs of operation and development, 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. A field examination was not considered necessary for the purposes of this report.

Definition 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 established 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 follows:

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

(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." 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 or on behalf of Eni, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

The proved undeveloped reserves estimates were based on opportunities identified in the plans of development provided by or on behalf of Eni.

Eni has represented that it has confirmed through its corporate ownership that the operator is committed to the development plans provided by or on behalf of Eni and that the operator has the financial capability to execute the development plans, including the drilling and completion of wells and the installation of equipment and facilities.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and original gas in place (OGIP). Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material-balance and other engineering methods were used to estimate OOIP and OGIP.

When applicable, 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.

When applicable, other engineering methods were used to estimate recovery factors based on analysis of reservoir performance, including production rate, reservoir pressure, and reservoir fluid properties.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in production-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production as defined under the Definition of Reserves heading of this report.

In certain cases, reserves were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous wells and reservoirs for which more complete historical performance data were available.

Data provided by or on behalf of Eni from wells drilled through December 31, 2025, and made available for this evaluation were used to prepare the reserves estimates herein. The reserves estimates were based on consideration of monthly production data available only through October 2025. Estimated cumulative production, as of December 31, 2025, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 2 months.

Oil and condensate reserves estimated herein are to be recovered by normal field separation. LPG reserves estimated herein consist primarily of propane and butane fractions and are the result of low-temperature plant processing. Oil, condensate, and LPG reserves included in this report are expressed in millions of barrels (10^6bbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil, condensate, and LPG reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as marketable gas and fuel gas. Marketable gas is defined as the total gas produced from the reservoir after reduction for shrinkage resulting from field separation; processing, including removal of the nonhydrocarbon gas to meet pipeline specifications; and flare and other losses but not from fuel usage. Fuel gas is defined as that portion of the gas consumed in field

operations. Gas reserves estimated herein are reported as marketable gas reserves; therefore, fuel gas is included as reserves. Marketable gas reserves estimated herein include 76 billion cubic feet ($10^9 ft^3$) of fuel gas. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.7 pounds per square inch absolute (psia). Gas quantities included in this report are expressed in $10^9 ft^3$.

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein consist of both associated and nonassociated gas.

Primary Economic Assumptions

This report has been prepared using initial prices, expenses, and costs provided by or on behalf of Eni in United States dollars (U.S.$). 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:

Oil, Condensate, LPG, and Gas Prices

Prices were furnished for each field and were held constant for the remaining producing lives of the fields. The oil, condensate, LPG, and gas prices provided were represented to be 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. Price differentials to a Brent oil reference price of U.S.$69.29 per barrel were provided for each field on behalf of Eni. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were U.S.$69.37 per barrel of oil, U.S.$66.51 per barrel of condensate, and U.S.$40.97 per barrel of LPG. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was U.S.$12.86 per thousand cubic feet of gas.

Operating Expenses, Capital Costs, and Abandonment Costs

Operating expenses and capital costs were estimated based on information provided by or on behalf of Eni and referenced to existing economic conditions. In certain cases, future expenditures, either higher or lower than existing expenditures, may have been used because of anticipated changes in operating conditions, but no general escalation that might result from inflation was applied. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by or on behalf of Eni and were not adjusted for inflation. The abandonment costs are inclusive of costs incurred for existing wells and facilities as well as those for future development associated with the proved reserves estimated herein. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of the undeveloped reserves estimated herein.

Taxes and Royalty

The fields evaluated herein are subject to a Norway ordinary tax and a special petroleum tax that combine to a marginal tax rate of 78 percent. For corporate tax purposes, depreciation is based on the application of the straight-line method over 6 years. Tax reimbursement for the cost of field abandonment is considered during the year of abandonment and the following forecast year. There is no royalty for the fields evaluated herein.

In our opinion, the information relating to estimated proved reserves of oil, condensate, LPG, 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, and 1202(a) (1), (2), (3), (4), (8) of Regulation S–K of the SEC; provided, however, that estimates of proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

DeGolyer and MacNaughton has performed an independent evaluation of the extent of the estimated net proved oil, condensate, LPG, and marketable gas reserves of certain properties located offshore Norway in which Eni has represented it holds an interest through its 63.04-percent corporate ownership of Vår Energi ASA.

The estimated net proved reserves, as of December 31, 2025, of the properties evaluated herein were based on the definition of proved reserves of the SEC and are summarized as follows, expressed in millions of barrels (10^6bbl) and billions of cubic feet (10^9ft^3):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2025	
	Oil, Condensate, and LPG (10^6bbl)	**Marketable Gas (10^9ft^3)**
Total Proved	339	1,062

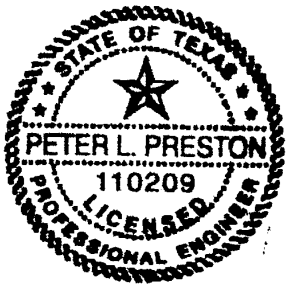
While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2025, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Eni. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Eni. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716



Peter L. Preston

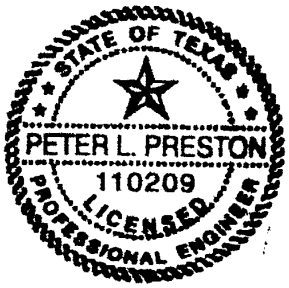
Peter L. Preston, P.E.
Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Peter L. Preston, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Vice President with DeGolyer and MacNaughton, which firm did prepare the report of third party addressed to Eni dated February 16, 2026, and that I, as Vice President, was responsible for the preparation of this report of third party.

2. That I attended Texas A&M University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1999; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers; and that I have more than 26 years of experience in oil and gas reservoir studies and evaluations.



Peter L. Preston, P.E.
Vice President
DeGolyer and MacNaughton

TABLE 1

Country Field
Norway
Albuskjell
Asgard
Balder
Bauge
Breidablikk
Byrding
Duva
Ekofisk
Ekofisk West
Eldfisk
Embla
Fenja
Fram
Gjoa
Goliat
Grane
Gudrun
Gungne
Halten East
Heidrun
Hyme
Johan Castberg
Kristin
Mikkel
Morvin
Njord
Ormen Lange
Ringhorne East
Sigyn
Sleipner East
Sleipner West
Snohvit
Snorre
Statfjord
Statfjord East
Statfjord North
Svalin
Sygna
Tommeliten Alpha
Tommeliten Gamma
Tor
Tordis
Trestakk
Tyrihans
Vega
Vigdis