



Eni.S.p.A
Mr. Pietro Giuseppe Consonni
Via Emilia 1
20097 San Donato Milanese
Milan, Italy

22nd of February 2019

Dear Mr. Consonni

In accordance with its agreement with Eni S.p.A (Eni or “the Client”), SGS Nederland B.V. , its Subsurface consultancy division (hereinafter “SGS”) has conducted an independent Proved reserves audit (hereinafter “the Audit”) of the proved reserves as of December 31st, 2018 estimated by Eni on a property located in the Sub-Saharan Africa Geographical Area of which ENI has an interest subject to the terms of an Exploration and Production Concession Contract (EPCC). This third party report was completed on February 20th, 2019 and, on Eni’s request, is intended for public disclosure by Eni in filings to the United States Securities and Exchange Commission (SEC).

Proved Reserves estimates are based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14th, 2009 in the Federal Register (SEC regulations).

The Proved reserves included herein are expressed as net Eni reserves and are based on the signed agreements with the government, the Sales and Purchases Agreement (SPA) signed with the buyer and using existing economic conditions.

Eni has advised that the net proved reserves attributable to the property reviewed by SGS represent 2% of Eni’s total proved net reserves, as of the 31st of December 2018. However, SGS is not in a position to confirm this statement as it was not requested to audit all other assets comprising Eni’s total proved reserves.

The Audit has been carried out following the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information”, approved by the SPE Board in June 2001 with revisions as of February 19th, 2007”, using Eni’s proved reserves estimates and other technical and commercial information provided by Eni to SGS up to December 31st, 2018.

Based on SGS’ review, including the data, methodology and interpretations provided by Eni, it is SGS’ opinion that the overall procedures, methodologies and thoroughness used by Eni in the proved reserves estimation process are appropriate and that a thorough approach has been followed, using methods considered sound in the determination of the net proved reserves. The quality of the data relied upon and the depth and thoroughness of the reserves estimation process as well as the classification and categorization of the proved reserves by Eni are appropriate and conform with the current regulations in part 210, Rule 4-10(a) Regulation S-X of the United States Securities and Exchange Commission (see Appendix 1).

The net proved reserves estimated by SGS for the property being audited are, on the aggregate, reasonable and within 4.9% of Eni’s net proved reserves estimates.

The Audit conclusions presented in the SGS report are based on constant average hydrocarbon prices as per SEC regulations and on the contractual price formulae determined by the signed Sales and Purchases Agreement (SPA). Proved reserves are the “as sold” volumes, as specified in the signed SPA, and therefore no uncontracted volumes have been included in the proved reserves estimated by SGS. Where appropriate, prices reflect the signed SPA terms and conditions. Eni’s share of gas volumes consumed in own operations has been included as proved reserves. To the best of its knowledge, SGS is not aware of any global-, regional- or country-regulations that could impact the envisaged ongoing development.



1. METHODOLOGY, PROCEDURES, UNCERTAINTIES AND ASSUMPTIONS, PRICES AND COSTS

1 METHODOLOGY, PROCEDURES, UNCERTAINTIES AND ASSUMPTIONS

Technical and commercial information provided to SGS on this property consisted of engineering, geoscience and commercial data, including but not limited to well logs, well test data, core data, core analysis, seismic data, pressure data, sedimentological and geological modelling. The estimation of reserves was carried out using appropriate principles and techniques commonly used and accepted by the Oil and Gas industry, including but not limited to volumetric estimates, material balance, analogs, approval documents to establish the project's maturity and contractual terms and conditions that allowed the estimation, to the economic limit, of the proved reserves. Furthermore, the process engineering from wellhead to the terminal point of sales has been reviewed and found sound and accurate. The techniques used rely on engineering and geo-scientific interpretation and judgment; hence the resources included in this evaluation are estimates only and should not be construed to be exact quantities. It should be recognized that such estimates of hydrocarbon resources may increase or decrease in future if there are changes to the technical interpretation, economic criteria, sales volumes or regulatory requirements. Property descriptions, details of interests held, well data, and commercial terms and conditions including fiscal, as obtained from Eni or public sources, were accepted as represented.

As part of this study SGS has audited the static models made available by Eni and has validated the key uncertainties and their range of uncertainty. The sensitivity analysis carried out by Eni using the identified uncertainties to quantify their individual impact, was also audited by SGS who found the approach and methodology sound. The reviewed work demonstrated that the key subsurface uncertainties are in the Gas Initially In Place (GIIP) driven by structural uncertainty away from the existing wells, reservoir properties and by the hydrocarbon volumes below the Lowest Known Hydrocarbons (LKH) not included in the evaluation of the proved reserves. Sensitivity analysis also indicated that the impact of the dynamic uncertainties is considered to be insignificant, given the degree of available local and regional information. Multiple reservoir realizations were used to generate a cumulative frequency distribution of the Gas Initially in Place. In its Audit, SGS has selected a deterministic reservoir model realization associated to the Lowest Known Hydrocarbon (LKH), close to the P90 static GIIP volume, which represents the Low GIIP estimate.

As part of the Audit, SGS developed production forecasts of wellhead gas using a material balance model and Eni's approved Field Development Plan, using the low GIIP as determined above and conservative dynamic parameters. The wellhead gas production profile was subsequently translated (using available process engineering tools) into volumes required to operate the facilities (fuel gas) from the wellhead to the terminal point, volumes of Liquefied Natural Gas available for sale, at the terminal point, as per contractual terms in the signed SPA, as well as the profile of condensate sales also at the terminal point. The resulting sales of Liquefied Natural Gas and condensate, and fuel gas profiles, up to the termination of the SPA contract, were properly validated and processed through the economic model using existing economic conditions, the SPA commercial terms and conditions and Eni's net interest in the property with the terms and conditions of the EPCC, resulting in the net proved reserves of gas and liquids as estimated by SGS.

Comparison of the aggregate SGS' net proved reserves estimates were found to be within 4.9% of ENI's estimates, which showed the reasonableness of Eni's proved reserves figures.

The project was sanctioned by Eni (at the appropriate local, regional and corporate level) and its partners during 2017. Construction began in July 2017 and is expected to be completed before 2022, with first gas expected in mid-2022. Eni has indicated that they are not aware of any legal, regulatory, political or economic obstacles that would impact the completion of this project as planned.

SGS has carried out the procedures needed to provide an opinion of the appropriateness of the methodologies, the adequacy and quality of the data and the depth and thoroughness of the reserves estimation process used by Eni and the classification and categorization of the reserves appropriate to the SEC regulations. As stated above, the reasonableness of ENI's proved reserves estimates has also been assessed. SGS has made every effort to ensure that the interpretations presented herein are accurate and reliable in accordance with SEC regulations, good industry practice and its own quality management procedures.



SGS has not made any field examination of the property, and no consideration was given in this report to potential environmental liabilities that may exist. As described above, several uncertainties associated to the estimation of oil and gas reserves exist, as subsurface accumulations of oil and gas cannot be measured in an exact manner. Reserves estimates should only be regarded as estimates that may change as production performance and new information become available. However, in this case the proved reserves estimates are capped by the presently signed SPA.

1.1.1 HYDROCARBON PRICES

The hydrocarbon prices applied in this reserves audit have been provided by ENI and the revenue has been calculated as per agreed SPA terms and conditions, where the Liquefied Natural Gas price at the terminal point is linked to Brent and the Japan Korean Marker (JKM) netback, using as input existing economic conditions of prices and costs. The reference price applied is defined as the average price during the 12-month period prior to the ending date of the period covered by this report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month prior to the reference date. The price differential (with Brent) for the condensate has been provided by ENI and used in SGS' evaluation. The reference date for the audited reserves is December 31st, 2018.

The table below provides an overview of the prices used in the economic evaluation:

Geographic area	Product	Price reference	2018 Average Prices
Sub Saharan Africa	Condensate	Brent	53.57 USD/STB
Sub Saharan Africa	LNG	Brent	71.42 USD/STB
Sub Saharan Africa	LNG	JKM netback	7.33 \$/MMBTU

1.3 OPERATING COSTS, DEVELOPMENT COSTS AND ABANDONMENT COSTS

Operating costs, Development Costs and Abandonment costs were supplied by Eni and were reviewed by SGS on a high level. Most of the development costs are based on tendering from, and bids already awarded to, qualifying and reputable construction companies. The costs estimates seem to be reasonable and in line with similar developments. The operating cost profiles assume present conditions and were held constant throughout the field's life. Under the production license's terms and conditions Eni is allowed to recover all exploration costs related to this development incurred in the past, which has an impact on the reserves entitlement. The estimated net cost of abandoning the field and facilities was included in the economic evaluation. Some 33% of the total development costs have already been spent by end 2018.

2. STANDARDS OF INDEPENDENCE AND PROFESSIONAL QUALIFICATION

2 SGS CERTIFICATION

Founded in 2001, SGS Horizon B.V. (now merged with SGS Nederland B.V, becoming its Subsurface consultancy division) based in The Netherlands, became part of the SGS Group in April 2008. Based in Switzerland, the SGS Group is the world's leading inspection, verification, testing and certification company. Recognized as the global benchmark for quality and integrity and independency, SGS Group globally employs over 95, 000 people and operate a network of more than 2,400 offices around the world.

As part of SGS' Oil, Gas and Chemicals Services, SGS Nederland B.V. provides integrated solutions throughout the field lifecycle, covering all subsurface, well and engineering aspects from exploration through development and production to abandonment. SGS also performs data room exercises and unitization/redetermination evaluations as well as estimation, auditing, classification and categorization of reserves and resources.



In the subject of reserves assessment, the in-house expertise has been acquired by senior personnel typically having significant pertinent industry experience within SGS or with oil majors, generally in positions of reserves related responsibility.

2.2 INDEPENDENCY

The SGS Group is known for its quality, integrity and independency. These values are also well embedded into the actions, and operations of the staff of the service group related to reserves certifications. The SGS Group nor any of its subsidiaries have any financial interests in Eni or in any of its affiliates. This includes potential shares in Eni. Fees are project-based and are not dependent on the outcome of the evaluation.

2.3 PRIMARY TECHNICAL PERSON UNDERTAKING THE RESERVES AUDIT

The technical, geological, commercial- and economic analyses performed have been carried out by a well experienced team, covering geoscientists, facilities engineers, petroleum engineers and economists from SGS. The qualifications of the technical person primarily responsible for the execution of this audit are provided in Appendix 2.

2.4 TERMS OF USE

This signed copy of this letter has been prepared for public disclosure in its entirety, in conjunction with Eni's annual filings to the SEC.

Very truly yours,

SGS Nederland B.V.
Primary Technical and
Commercial Person

Niek Douzi

Date: 22-FEB-2019

SGS Nederland B.V.

Richard Keen, Operations Manager

Date:

22-FEB-2019.

DEFINITIONS OF OIL AND GAS RESERVES

From the U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10 (a)

(a) Definitions

(1) Acquisition of properties. Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) Analogous reservoir. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- Same environment of deposition;
- Similar geological structure; and
- Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) Bitumen. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) Condensate. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

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

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

(7) Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) Estimated ultimate recovery (EUR). Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) Exploratory well. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) Extension well. An extension well is a well drilled to extend the limits of a known reservoir.

(15) Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) Oil and gas producing activities.

(i) Oil and gas producing activities include:

- (A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
- (B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
- (C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
 - (1) Lifting the oil and gas to the surface; and
 - (2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
- (D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

- a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
- b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term saleable hydrocarbons means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

- (ii) Oil and gas producing activities do not include:
 - (A) Transporting, refining, or marketing oil and gas;
 - (B) Processing of produced oil, gas or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
 - (C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
 - (D) Production of geothermal steam.

(17) Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

- (i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
- (ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
- (iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) Probabilistic estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter

(from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) Production costs.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities, they become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) Proved area. The part of a property to which proved reserves have been specifically attributed.

(22) 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.

(23) Proved properties. Properties with proved reserves.

(24) Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) Reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

(27) Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) Resources. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) Service well. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) Stratigraphic test well. A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as “exploratory type” if not drilled in a known area or “development type” if drilled in a known area.

(31) 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 paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) Unproved properties. Properties with no proved reserves.

APPENDIX 2

QUALIFICATIONS OF TECHNICAL PERSON PRIMARILY RESPONSIBLE FOR OVERSEEING THIS RESERVES AUDIT:

Niek Dousi, Senior Reservoir Engineer was the project manager and primary technical person primarily responsible for the execution and QA/QC of this audit. Niek Dousi has about 14 years of experience as a reservoir/petroleum engineer and has been involved in many reserves evaluations as technical staff/coordinator and project manager within SGS. In his role, he has been supported by key technical- and commercial specialists, some with over 30 years of professional experience in international oil and gas companies. Mr. Dousi holds an MSc in Petroleum Engineering from Delft University of Technology in The Netherlands. He joined SGS in 2005 and has participated as (lead) reservoir engineer and/or project manager in integrated reservoir studies, Acquisition and Divestment asset valuations and reserves assessments, using SPE-PRMS & SEC regulations. He has worked on assets primarily in the North Sea, Central Europe, North-, West- and East Africa, Oman and Australia. He has participated in numerous studies of oil- and gas assets worldwide, including tight gas, gas condensates, heavy oil, fluvial-, stacked- and fractured carbonate reservoirs. He is a long-standing member of the Society of Petroleum Engineers and has prepared- and presented papers for SPE and EAGE conferences.