2 March 2018

The Directors
Greenfields Petroleum Corporation
211 Highland Cross, Suite 250,
Houston, TX 77073,
USA

Dear Sirs,

Re: Evaluation of Certain Contingent Resources in the Bahar Oil and Gas Field and Prospective Resources in an Undrilled Prospect in the Gum Deniz Oil Field, Offshore Azerbaijan.

In accordance with your instructions, ERC Equipoise Ltd (ERCE) has carried out a review of certain Contingent and Prospective Resources associated with assets owned by Greenfields Petroleum Corporation (Greenfields) offshore Azerbaijan and reports herein said Contingent and Prospective Resources as at 2 March 2018, being the date to which ERCE reviewed available data. This is the effective date of this report.

ERCE has carried out this work using the March 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS) as the standard for classification and reporting. A summary of the PRMS is found in Appendix 1. Nomenclature used in this letter is summarised in Appendix 2.

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbon volumes. No site visit was undertaken in the preparation of this report. ERCE has relied upon information provided by Greenfields for the preparation of its estimates of Contingent and Prospective Resources.

ERCE has made every effort to ensure that the interpretations, conclusions and recommendations presented herein are accurate and reliable in accordance with good industry practice. ERCE does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees. In the case that material is delivered in digital format, ERCE does not accept any responsibility for edits carried out after the product has left the company's premises.

1. Contingent Resources, Fasila Reservoir, Bahar Field

1.1 Introduction

The Bahar field is located in shallow water 40 km southeast of Baku, offshore Azerbaijan in the South Caspian Basin. The field was discovered in 1968 and production began in 1969. The field has been developed from 76 offshore platforms. Gas and liquids are gathered at a central processing and metering platform and transported to shore via four 12-inch pipelines to handling facilities. Approximately 200 wells have been drilled into the Bahar field of which 101 have been retained and 10 wells are producing natural gas and condensate (as of 31st December 2017).

Hydrocarbons are found at depths between 2800 and 5500 m subsea. The main hydrocarbon resource in the upper part of the reservoir section is gas condensate. The main resource in the deeper Balakhany and Pereriv (also known as the Fasila, or FS) horizons is oil with gas caps. The field has been produced by depletion, primarily aimed at gas recovery. Reservoir pressure has declined significantly. Water injection into the Balakhany and Pereviv reservoirs for a relatively short period was undertaken in the 1980s through to the early 2000s, since when offtake has been minimal. Cumulative oil production of the two principal oil reservoirs amounts to less than 10% of stock tank oil initially in place (STOIIP).

Greenfields originally held a 33.33% working interest in the Bahar Production Sharing Agreement (PSA), effective as of October 2010. The PSA expires in January 2041. Greenfield acquired the remaining 66.67% of the Bahar project from the liquidators of its partner in August 2016 and now has 100% ownership of Bahar Energy and an 80% interest in the PSA. SOCAR (State Oil Company of the Azerbaijan Republic), holds the remaining 20% of the PSA. Bahar Energy Operation Company (Bahar Energy), wholly owned by Greenfields, plans to redevelop the Bahar field as well as the Gum Deniz oil field that lies to the north of Bahar.

Bahar Energy plans to initiate a waterflood of the FS reservoir in Bahar in 2019 starting with the implementation of five waterflood pilots. These would involve the workover conversion of five existing wells to water injection wells coupled with the installation of mobile salt water injection facilities on each of the injection well platforms to deliver an adequate supply of filtered and treated injection water. A total of eight wells would be offsetting production wells which would be monitored for pressure and fluid response.

Assuming a positive reservoir response to the pilot flood, a full-scale water injection project would be implemented by Bahar Energy. Initially the drilling of two down dip injection wells located in the water leg of the FS reservoir would be carried out. The drilling of a total of nine injection wells is envisaged over a five-year period from three existing platforms and one new platform to be constructed on the western flank of the reservoir. A new 12-inch produced liquids line would be required to handle the increased liquid production.

1.2 Data Available for Review

ERCE was provided with a static model, simulation models for both the Upper and Lower FS reservoirs, well log data, well tops, pressure data, test data and historical production data. The sparse 2D seismic data were not made available for this study.

Data are generally poor quality, typical for fields drilled up in Former Soviet Union (FSU) countries in the last century. Modern open hole log data are not available; core data from the FS reservoir comprise five plugs. Petrophysical interpretation is very uncertain. Fluid property (PVT) data are not available. Commingled production has been the norm and allocation of production between reservoirs is uncertain. There are no bottom hole pressure measurements; reservoir pressure has been calculated from surface measurements and is poorly calibrated.

1.3 Reservoir Description and Hydrocarbons Initially in place

The Bahar field is a large north-south oriented anticlinal structure, bounded to the west by a large fault. The structure is understood to have some degree of segmentation due to the presence of faults believed to trend southwest-northeast. The degree of segmentation is likely to vary within different reservoir intervals and is difficult to map due to only spare 2D seismic data across the field. Historical attempts at mapping segmentation have largely been based around available well pressure and production data and have had limited success. Due to the lack of high quality pressure and seismic data ERCE has treated the FS Upper and Lower reservoirs as unsegmented.

The Fasila reservoir interval at Bahar ranges in thickness from 140 m to 190 m and consists of medium to coarse grained fluvial-deltaic sandstones interbedded with shales. The thicknesses of the sand beds do not vary sharply across the field. The reservoir quality is generally good, with average porosity of the sands estimated to be between 15% and 18% with 45 to 250 mD average permeability.

Oil production from the FS reservoir commenced in 1971 and reached a peak of 5200 stb/d in 1978. Cumulative oil production to date is 24.5 MMstb. Gas production peaked at 72 MMscf/d in 1988. Cumulative gas production to date is 277 Bscf. Water injection commenced in 1984 and reached a maximum rate of 15 Mbbl/d in 1991. Cumulative water injection to date is 41 MMbbl.

After undertaking an audit ERCE has accepted the petrophysical interpretation of the log data presented by Greenfields. Our estimate of a most likely original gas oil contact (GOC) is at 4490 mTVDSS. Our estimates of most likely oil water contact (OWC) are at 4610 and 4670 mTVDSS for the Upper and Lower FS reservoir respectively, giving oil column thicknesses of 120 and 180 m.

We have calculated a best estimate of stock tank oil initially in place (STOIIP) of 343 MMstb, and of free gas initially in place (GIIP) of 205 Bscf. Our best estimates of associated GIIP and condensate initially in place (CIIP) are 479 Bscf and 13 MMbbl.

1.4 Contingent Resources

Greenfields has constructed a simulation model of the FS reservoir and carried out a field-level history match of the production. Well by well history matching has not yet been undertaken. Greenfields has used this model to prepare forecasts of production under the planned pilot water injection scheme and the follow-up full field waterflood.

ERCE has carried out a material balance analysis and has reviewed the forward forecast of the field and the historical performance on both a field and individual well basis. We have carried out a review of analogues available in the public domain. ERCE has also reviewed the simulation model provided along with its associated sensitivities.

Analysis of past performance, in particular the response of nearby producers to the historical water injection in the field, is hampered by the poor data quality and the impact of reperforations masking the reservoir response. It is apparent that a successful future water injection scheme will require a change of behaviour from past response both in terms of reservoir re-pressurisation as well as improved sweep. Greenfields intends to inject materially more water to re-pressurise the reservoir.

The limited oil recovery to date, the likely favourable oil viscosity and generally good reservoir quality offer the potential for further oil recovery from the FS reservoirs. On the other hand, the significant reduction in reservoir pressure (currently some 200 bar, 275 bar below initial reservoir pressure) coupled with significant movements in the GOC and OWC since production began with limited data on the location of current contacts all mitigate against high incremental oil recovery in the future.

We assess low, mid and high estimates of incremental recovery factor under Greenfield's outline plan as 3, 6 and 12 % respectively. The oil recovery factor to date is 7%, giving low, mid and high estimates of recovery factor of 10, 13 and 19%. We have applied our estimates of incremental recovery factor to our best estimate of STOIIP of 343 MMstb to give the total unrisked oil Contingent Resources for the planned pilot water injection followed by a water flood of the Bahar FS reservoir. Table 1.1 presents estimates of gross and net unrisked oil Contingent Resources.

Table 1.1: Contingent Unrisked Oil Resources, Bahar field, Fasila Reservoir

Interval	Gross Unrisked Contingent Oil			Working	Net Unrisked Contingent Oil		
	1C	2C	3C	Interest	1C	2C	3C
Bahar Fasila	10.3	20.6	41.2	80.00%	8.2	16.5	32.9

Notes
1) "Gross Contingent Resources" are 100% of the volumes estimated to be recoverable from the field without any economic cut-off being applied.
2) "Net Contingent Resources" are Greenfields' working interest fraction of the gross contingent resources
3) Contingent Resources are estimates of volumes that might be recovered from the field under as yet undefined development scheme(s). It is not certain that the field will be developed or that the volumes reported as Contingent Resources will be recovered.
4) The volumes reported here are unrisked in that they have not been multiplied by a chance of development.

2. Prospective Resources, Miocene Reservoir, Gum Deniz Field

2.1 Introduction

The Gum Deniz field is located south of the Absheron peninsula, 21 km south of Baku, between Gum Island and the Bahar field. The field extends from onshore Gum Island, which is 2.5 km from the mainland to the south in the Caspian Sea. The field has been on production since 1955 and has been developed with approximately 70 platforms. Oil, water and gas are transported via a main collector pipeline across Gum Island to onshore treatment facilities. Currently 24 of 155 retained wells are on production (as of 31st December 2017).

Greenfields has mapped a structural closure at Miocene level at a depth of between 4000 and 4500 m ss. The prospective horizon is beneath the producing reservoirs of the Gum Deniz field that has not yet been penetrated by a well.

Greenfields is monitoring the drilling of the Absheron Operating Company (AOC) Miocene well test which is located approximately 4 km north east of the Bahar PSA. The well is being drilled from the same surface location as the 2015 Hovsan 1870 gas discovery well which reportedly encountered high pressure gas and condensate in the top of the Miocene at approximately 4600 m ss. The well reportedly also encountered high bottom hole pressures in excess of 11,000 psi.

An exploration well to the Miocene is estimated to cost between US$25 to 30 millions in order adequately to contain the high pressures anticipated in the Miocene reservoirs. As the PSA has cost recovery ringfencing for the entire rehabilitation area, the exploration well costs can be recovered from the production revenues from other Bahar PSA projects, therefore reducing the dry hole cost exposure. A successful exploration well should lead to early exploitation of the hydrocarbons through existing pipelines and gas processing facilities.

2.2 Data Available for Review

ERCE was provided with a Petrel project containing seismic data (both PSTM and PSDM along with various filtered volumes), seismic interpretation of the base Miocene prospect and younger reservoir horizons interpreted on the PSDM volume and well data for younger Gum Deniz field reservoirs.

2.3 Prospect Description, Prospective Resources and Chance of Success (COS)

The Miocene prospect is located under the Gum Deniz field below the younger Productive Series reservoirs with crestal depths estimated to be between 4000 m and 4500 m ss. The structure is a four-way dip closure defined on 3D seismic data, potentially extending to the north, beyond the limits of the seismic. The Miocene reservoirs are believed to comprised of stacked Chokrak, Maykop and Koun formation sandstones. Based upon limited analogue information it is expected that the reservoir will have a low net to gross ratio comprising relatively thin reservoir sands. Porosity of the sands is expected to be between 9% to 15%.

ERCE has reviewed the data provided and has made independent estimates of GIIP and Prospective Resources. We have reviewed the seismic data and interpretations presented and adjusted them to derive a range of gross rock volume (GRV) estimates based upon assumed spill points. ERCE has made estimates of net to gross ratio, porosity and gas saturation based on regional analogue data.

ERCE has risked the prospect based on a four-component risk matrix taking into account the available seismic data and interpretation. ERCE has assigned a COS to the prospect of 32% based on our understanding of the source, reservoir, trap and seal. The Miocene interval is rich in in high TOC shales within which the reservoir sands are interbedded. As such, the risk of charge, migration and sealing capacity to the prospect is low. ERCE has assigned higher risk to the presence and quality of the reservoir as there is evidence of erosion and thinning of seismic packages onto the crest of the structure so reservoir sands may not be present. The trap also has a higher risk assigned to it as the poor quality of the seismic in places makes it difficult to define in some areas.

Table 1.2 presents estimates of unrisked and risked gross and net gas and condensate Prospective Resources for the Miocene prospect in the Gum Deniz field.

Table 1.2: Prospective Resources, gross and net to Greenfields, Gum Deniz Miocene Prospect

	GIIP (Bscf)			Gross Unrisked Prospective Gas Resources (Bscf)				Working Interest (%)	Net Unrisked Prospective Gas Resources (Bscf)				COS (%)	Net Risked Prospective Gas Resources (Bscf)			
	Low	Mid	High	Low	Mid	High	Mean		Low	Mid	High	Mean		Low	Mid	High	Mean
Miocene Prospect	78.0	332.5	1364.5	49.9	214.4	891.2	392.0	80%	39.9	171.5	713.0	313.6	32%	12.8	54.9	228.1	100.4

	CIIP (MMbbl)			Gross Unrisked Prospective Condensate Resources (MMbbl)				Working Interest (%)	Net Unrisked Prospective Condensate Resources (MMbbl)				COS (%)	Net Risked Prospective Condensate Resources (MMbbl)			
	Low	Mid	High	Low	Mid	High	Mean		Low	Mid	High	Mean		Low	Mid	High	Mean
Miocene Prospect	4.9	22.3	96.9	2.4	10.8	47.2	20.6	80%	1.9	8.6	37.7	16.5	32%	0.6	2.8	12.1	5.3

Notes

1) Prospects are features that have been sufficiently well defined through analysis of geological and geophysical data that they are likely to become drillable targets.

2) “Gross Unrisked Prospective Resources” are 100% of the volumes estimated to be recoverable from an accumulation

3) “Net Unrisked Prospective Resources” are Greenfields’ working interest fraction of the gross resources

4) "Net Risked Prospective Resources" are Greenfields’ working interest fraction of the gross resources multiplied by the geological chance of success (COS).

5) The geological chance of success (COS) is an estimate of the probability that drilling the prospect would result in a discovery as defined under SPE PRMS.

6) Prospective Resources reported here are “risked” in that the volumes have been multiplied by the COS.

ESMA App III (iii) (1)

Confirmations and Professional Qualifications

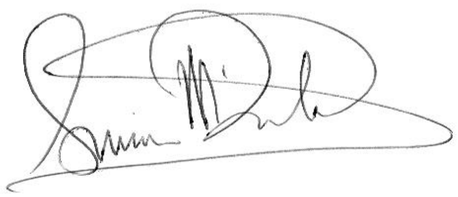
ERCE has the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets.

The work has been supervised by Mr Simon McDonald, Engineering Director of ERCE, a Chartered Engineer and President of The Society of Petroleum Evaluation Engineers, who has over 40 years’ experience in the evaluation of oil and gas fields and acreage, preparation of development plans and assessment of reserves and resources.

Mr Simon McDonald is independent of Greenfield, its directors, senior management and its other advisers and has no economic or beneficial interest (present or contingent) in the Company or in any of the mineral assets evaluated and is not remunerated by way of a fee that is linked to the admission or value of the issuer.

Yours faithfully

ERC Equipoise Limited



Simon McDonald
Engineering Director, ERC Equipoise Ltd.

1. SPE PRMS Guidelines

SPE/WPC/AAPG/SPEE Petroleum Reserves and Resources Classification System and Definitions

The Petroleum Resources Management System

Preamble

Petroleum Resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum Resources managements system provides a consistent approach to estimating petroleum quantities, evaluating development projects and presenting results within a comprehensive classification framework.

International efforts to standardize the definitions of petroleum Resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum Resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in Resources definitions (2005). SPE also published standards for estimating and auditing Reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of Resources estimation. However, the technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE-PRMS consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum Resources. It is expected that the SPE-PRMS will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The full text of the SPE/WPC/AAPG/SPEE Petroleum Resources Management System document, hereinafter referred to as the SPE-PRMS, can be viewed at

www.spe.org/specma/binary/files6859916Petroleum_Resources_Management_System_2007.pdf .

Overview and Summary of Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulphide and sulphur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "Resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE Resources classification system. The system defines the major recoverable Resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

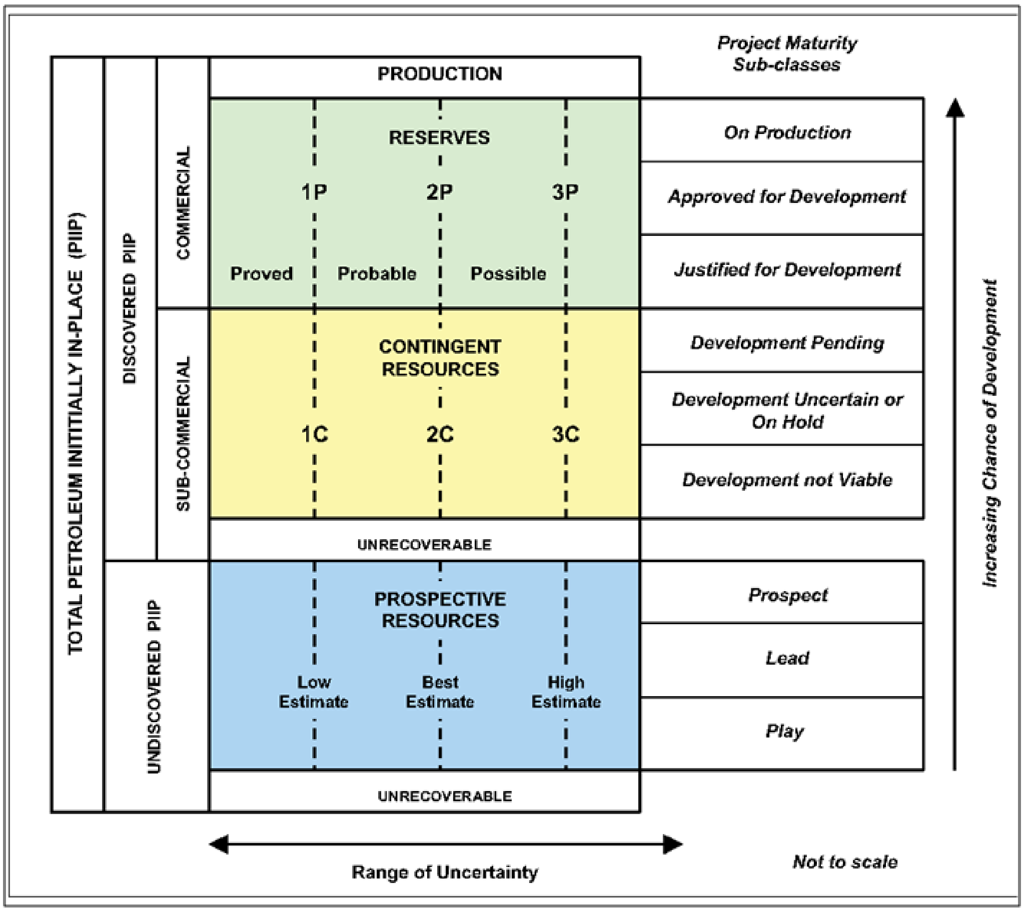


Figure 1-1: SPE/AAPG/WPC/SPEE Resources Classification System

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Development", that is, the chance that the project that will be developed and reach commercial producing status.

The following definitions apply to the major subdivisions within the Resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE

Total Petroleum Initially in Place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations.

It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "Total Resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE

Discovered Petroleum Initially in Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION

Production is the cumulative quantity of petroleum that has been recovered at a given date.

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.

In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

Proved Reserves

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express 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. The area of the reservoir considered as Proved includes:

the area delineated by drilling and defined by fluid contacts, if any, and adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved Reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive and interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.

For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogues and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves

The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project.

Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects.

In conventional accumulations, Probable and/or 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 minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area.

Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources.

In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

CONTINGENT RESOURCES

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE

Undiscovered Petroleum Initially in Place is that quantity of petroleum that is estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES

Prospective Resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analogue developments in the earlier phases of exploration.

Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

Play

A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

• There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

• There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

• There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately.

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1-1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete Resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project.

2. Nomenclature

2.1. Units and their abbreviations

bbl	barrel
bbl/d	barrels per day
Bscf	thousands of millions of standard cubic feet
boe	barrels of oil equivalent, where 6000 scf of gas = 1 bbl of oil
km	kilometres
m	metres
M or MM	thousands and millions respectively
md	millidarcy
mTVDSS	metres subsea
psia	pounds per square inch absolute
rb	reservoir barrels
scf	standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
scf/d	standard cubic feet per day
stb	a stock tank barrel which is 42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
stb/d	stock tank barrels per day

2.2. Resources Categorisation

The following are SPE PRMS terms, defined in Appendix 1:

Low, or P90	90 per cent probability
Best, or P50	50 per cent probability
High, or P10	10 per cent probability
1C	Low Estimate of Contingent Resources
2C	Best Estimate of Contingent Resources
3C	High Estimate of Contingent Resources

2.3. Terms and their abbreviations

GIIP	gas initially in place
GOC	gas oil contact
GRV	gross rock volume
GWC	gas water contact
OWC	oil water contact
PSA	Production Sharing Agreement

PSDM	post stack depth migration
PSTM	post stack time migration
PVT	pressure volume temperature experiment
STOIIP	stock tank oil initially in place