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.

at 31st December 2018

Prepared For:	Greenfields Petroleum Corporation
By:	ERCE
Date:	24 January 2019

ERCE
Independent Energy Experts

Approved by: S McDonald

Date released to client: 24 January 2019

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

The Directors,
Strand Hanson Limited
26 Mount Row
Mayfair
London, W1K 3SQ
United Kingdom

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 Pte Ltd ("ERCE") has carried out an independent evaluation for Greenfields Petroleum Corporation ("Greenfields" or the "Company") of certain assets located in the Bahar PSA license area (the "License"), offshore Azerbaijan. We note that this report comprises an assessment of certain Contingent and Prospective Resources in the License and does not seek to assess the Reserves within the License which are reported on separately by GLJ Petroleum Consultants Ltd.

ERCE has been informed that the Company is intending to publish an admission document in connection with its proposed admission to trading of the Company's common shares on the AIM market of the London Stock Exchange ("AIM") ("Admission") as required under the AIM Rules for Companies and that as part of this it is required to include a report on the Company's reserves and resources. This competent persons report ("CPR") has been compiled in accordance with the guidelines and scope and content of a CPR, as set out in the AIM rules for companies including the "Note for Mining and Oil and Gas Companies", as published by the London Stock Exchange in June 2009, for the purpose of publication in an AIM admission document.

This Competent Person's Report ("CPR") has been completed in accordance with the guidelines, scope and content of a CPR, as set out in the AIM Rules for Companies including the "Note for Mining and Oil and Gas Companies", as published by the London Stock exchange in June 2009, for the purposes of publication in an AIM admission document.

The asset resources evaluation has an effective date of December 31, 2018. ERCE has reviewed data made available through to December 31, 2018. So far as we are aware, having made reasonable enquiries, no material change in the asset reserves and resources has occurred from December 31, 2018 to the date of this document, being January 24, 2018, which would require any amendment to this Competent Persons Report (CPR).

ERCE has carried out this work using the 2018 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. The full text can be downloaded from https://secure.spee.org/sites/spee.org/files/prmgmtsystem_final_2018.pdf.

ERCE is an independent consultancy specialising in geoscience evaluation, engineering and economic assessment. ERCE will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this CPR or on Admission and ERCE will receive no other benefit for the preparation of this CPR. ERCE does not have any pecuniary or other interests that could reasonably be regarded as capable of affecting its ability to provide an unbiased opinion in relation to the resources and reserves and the projections and assumptions included in the various technical studies completed by the Company, opined upon by ERCE and reported herein.

Neither ERCE nor the Competent Person who is responsible for authoring this CPR, nor any Directors of ERCE have at the date of this report, nor have had within the previous two years, any shareholding in the Company or Strand Hanson Limited ("Strand Hanson"), or any other economic or beneficial interest (present or contingent) in any of the assets being reported on. ERCE is not a group, holding or associated company of the Company or Strand Hanson. None of ERCE's partners or officers nor any Competent Person involved in the preparation of this CPR, are officers or proposed officers or employees of any group, holding or associated company of the Company or Strand Hanson.

Consequently, ERCE, the Competent Persons and the Directors of ERCE consider themselves to be independent of the Company, its directors, senior management and Strand Hanson.

The work has been supervised by Mr Simon McDonald. Mr McDonald has over 40 years of experience in the evaluation of oil and gas fields, preparation of development plans and assessment of reserves and resources. He holds a MSc degree in Petroleum Engineering from Imperial College London and a BSc (Hons) degree in Civil Engineering from Leeds University. He is a Chartered Engineer and President of the Society of Petroleum Evaluation Engineers. Mr McDonald qualifies as a Competent Person as defined by the AIM Rules.

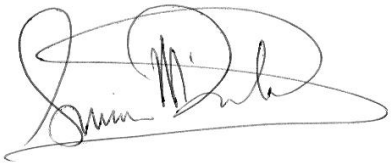
ERCE accepts responsibility for this CPR and for all of the technical information that has been directly extracted from the CPR and reported in the admission document to be released by the Company in connection with Admission and to be dated around the same date as this letter.

ERCE declares that it has taken all reasonable care to ensure that the information contained in the CPR and included in the admission document is, to the best of its knowledge, in accordance with the facts and contains no omission likely to affect its import.

In accordance with the AIM Rules for Companies, ERCE confirms that the presentation of information contained elsewhere in the admission document which relates to information in the CPR is accurate, balanced and not inconsistent with the CPR.

This report is addressed to Greenfields, and its Nominated Adviser, Strand Hanson. ERCE understands that this report will be included in an admission document to be published by Greenfields (the “Admission Document”). For the purposes of the AIM Rules for Companies, ERCE is responsible for this report as part of the Admission Document and declares that it has taken all reasonable care to ensure that the information contained in this report is, to the best of its knowledge, in accordance with the facts and contains no omission likely to affect its import.

Yours faithfully,



Simon McDonald
for and on behalf of ERC Equipoise Limited

1. Contingent Resources, Fasila Reservoir, Bahar Field

1.1. Introduction

The Bahar field is located in shallow water due south of the Gum Deniz field (Figure 1-1), 40 km southeast of Baku, offshore Azerbaijan in the South Caspian Basin.

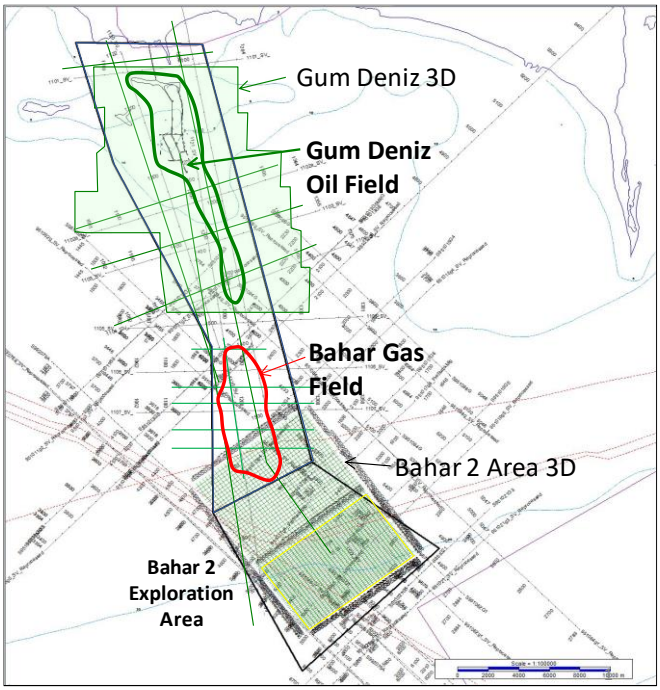


Figure 1-1: Bahar and Gum Deniz field outlines and seismic surveys

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 nine wells are producing natural gas and condensate (as of 31st December 2018).

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 Pereviv (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. Greenfields 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.

A summary of Greenfields interest in the PSA is presented in Table 1-1.

Table 1-1: Summary of Greenfields' Licence Interest

Country	Licence	Holder	Interest (%)	Licence expiry date	Licence area (acres)	Asset	Status
Azerbaijan	Bahar PSA	Bahar Energy Limited***	80%	Jan-41	76,500	Bahar	Re-development*
						Gum Deniz	Exploration**

*This CPR addresses the potential for waterflooding the mature Bahar field

**This CPR addresses only the Prospective Resources underneath the producing Gum Deniz field.

*** Bahar Energy Limited is a wholly owned subsidiary of Greenfields Petroleum Corporation

Bahar Energy plans to initiate a waterflood of the FS reservoir in Bahar in 2021 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 sparse 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.

Figure 1-2 presents a schematic of the model grid showing well locations. Figure 1-3 shows average saturations in the model at initial conditions (date of discovery in 1968), in 2018 and at the end of the planned waterflood in 2041.

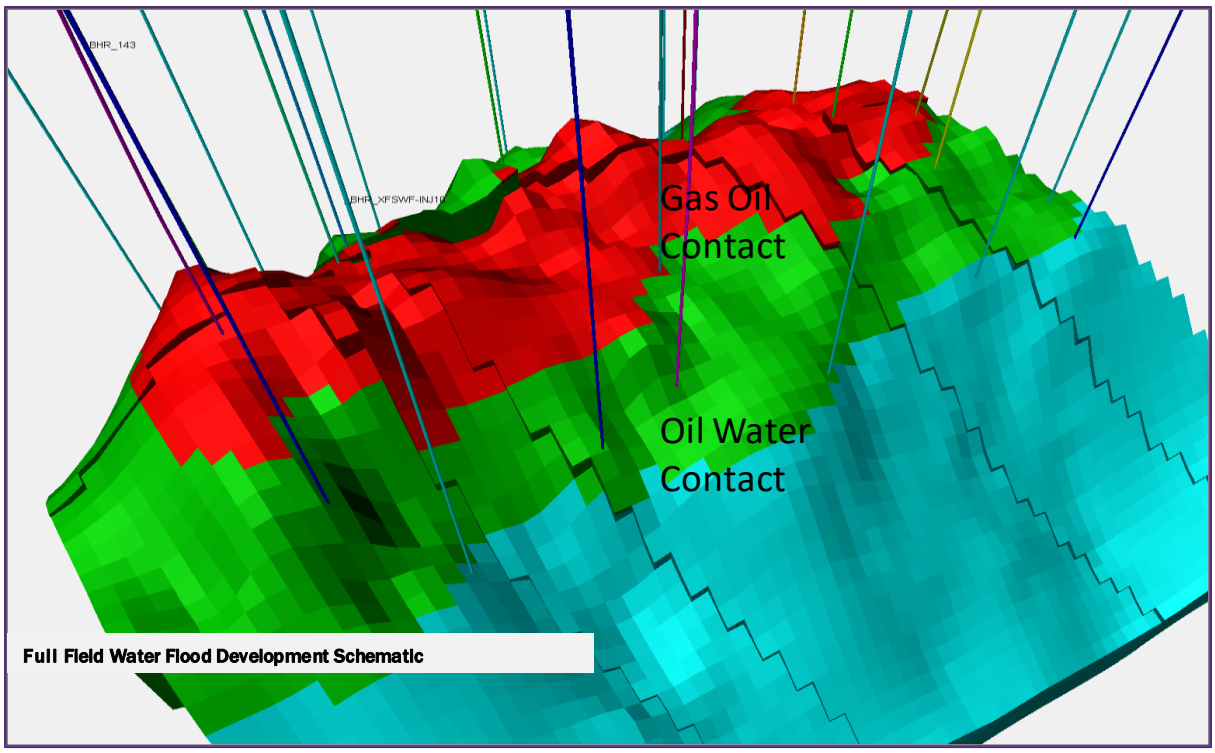


Figure 1-2: Schematic of Bahr simulation model grid

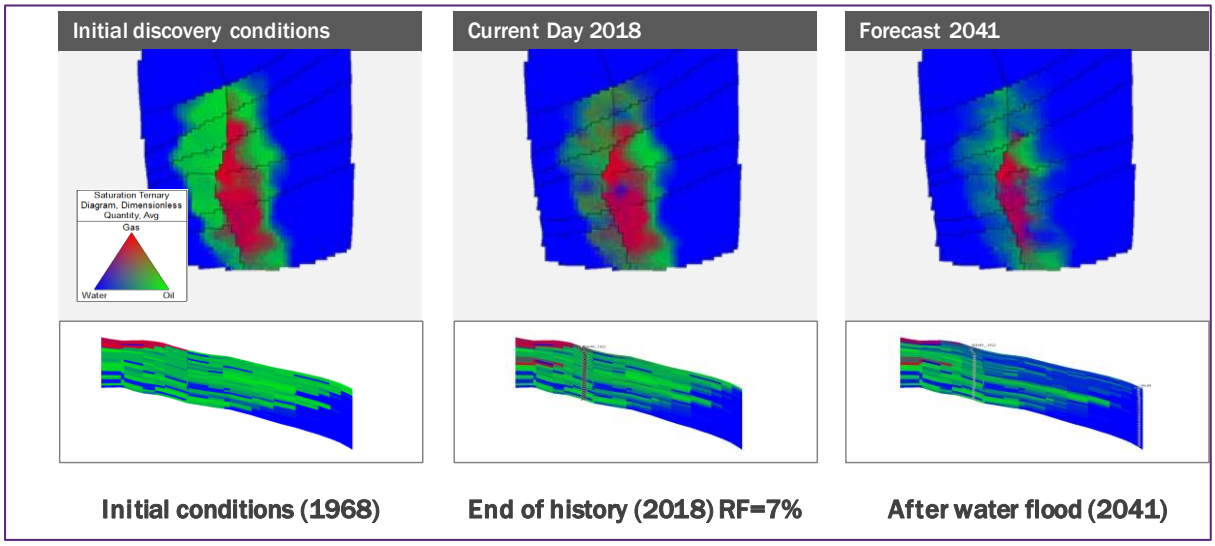


Figure 1-3: Schematic of average saturations in model at initial conditions, present day and after waterflood

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 1-2 presents ERCE's estimates of gross and net unrisked oil Contingent Resources.

Table 1-2: Unrisked Oil Contingent Resources, Bahar Field, Fasila Reservoir

Interval	Gross Unrisked Contingent Oil (MMbbl)			Working Interest (%)	Net Unrisked Contingent Oil (MMbbl)			Risk Factor (%)	Operator
	1C	2C	3C		1C	2C	3C		
Bahar Fasila	10.3	20.6	41.2	80%	8.2	16.5	32.9	70%	Greenfields

Notes

1) "Gross unrisked oil Contingent Resources" are 100% of the volumes estimated to be recoverable from the field without any economic cut-off being applied.

2) "Net unrisked oil 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 risk factor (chance of development).

2. Prospective Resources, Miocene Reservoir, Gum Deniz Field

2.1. Introduction

The Gum Deniz field is located north of the Bahar field (Figure 1-1), to the south of the Absheron peninsula, 21 km south of Baku. 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 22 of 155 retained wells are on production (as of 31st, December 2018).

Greenfields has mapped a structural closure at Miocene level at a depth of between 4000 and 4500 mTVDSS. 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 mTVDSS. 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 million in order to adequately 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 mTVDSS. 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 be 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 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 2-1 presents ERCE's estimates of unrisked and risked gross and net gas and condensate Prospective Resources for the Miocene prospect in the Gum Deniz field.

Table 2-1: Prospective Resources, Gross and Net to Greenfields, Gum Deniz Field, 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)				Operator
	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	Greenfields

	CIIP (MMbbl)			Gross Unrisked Prospective Condensate Resources (MMbbl)				Working Interest (%)	Net Unrisked Prospective Condensate Resources (MMbbl)				COS (%)	Net Risked Prospective Condensate Resources (MMbbl)				Operator
	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	Greenfields

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) COS is an estimate of the probability that drilling the prospect would result in a discovery of producible hydrocarbons.

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

3. Appendix 1: SPE PRMS Guidelines

This report references the SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Reserves and Resources Classification System and Definitions, as revised in June 2018 (PRMS). The full text of the PRMS document can be viewed at:

https://secure.spee.org/sites/spee.org/files/prmgmtsystem_final_2018.pdf.

Definitions of the key PRMS Reserves and Resource classes, categories and a glossary of related terms can be found at the above address.

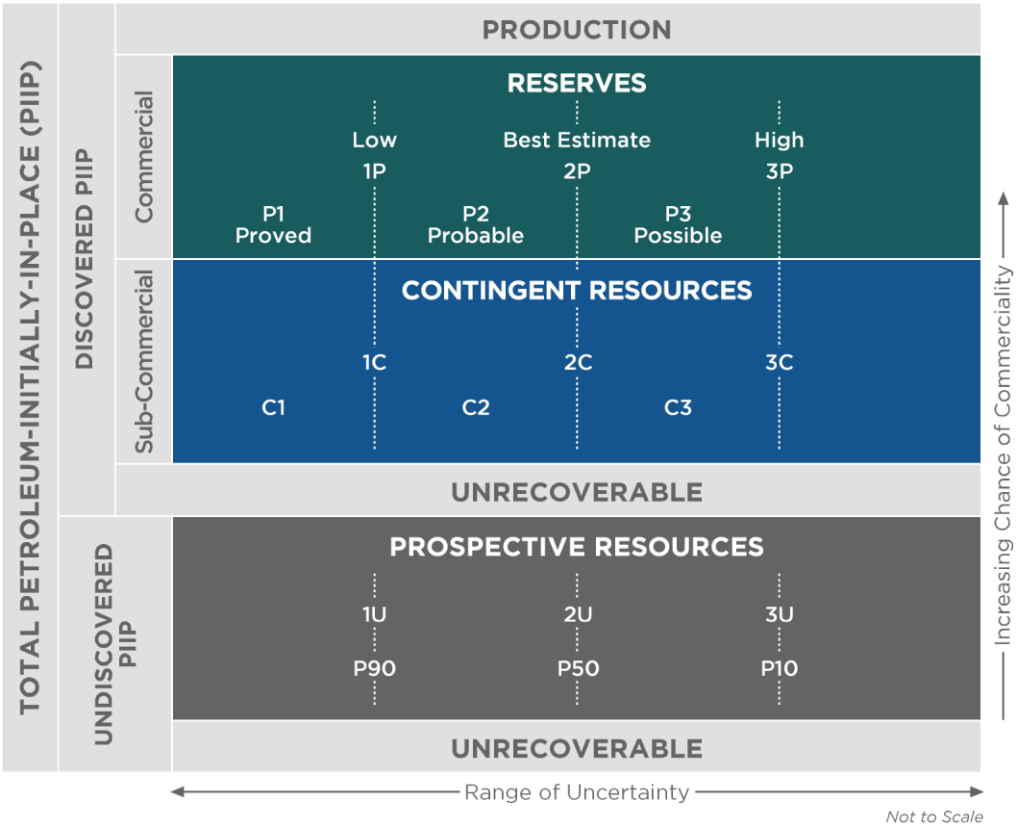


Figure A: PRMS Resources classification framework

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 1.1)

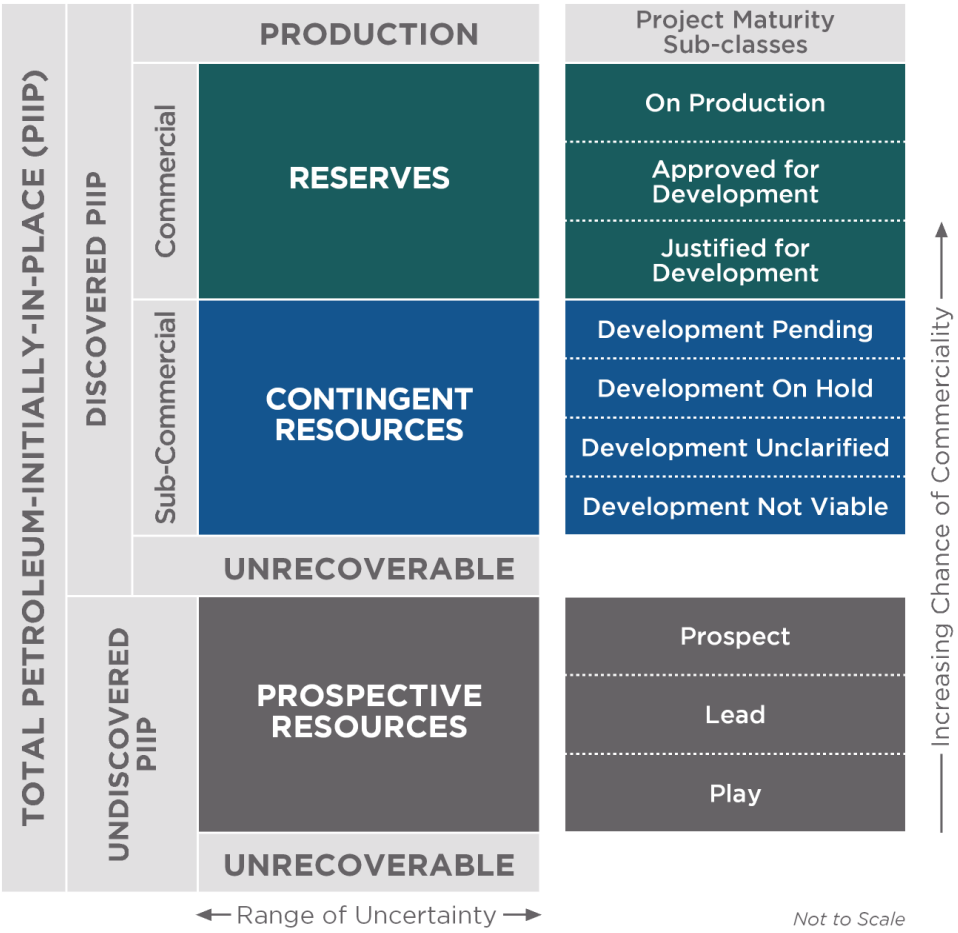


Figure B: PRMS Resources sub-classes

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 2.1)

Table 1: PRMS Recoverable Resources Classes and Sub-Classes

Classes/Sub-classes	Definition	Guidelines
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: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves 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 the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that 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 an economic project is 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 maturity and economic 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.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.

Classes/Sub-classes	Definition	Guidelines
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	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 owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. 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 the economic status.

Classes/Sub-classes	Definition	Guidelines
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

Classes/Sub-classes	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic 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 analog 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 geologic 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 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 geologic 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 that requires more data acquisition and/or evaluation 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 geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: PRMS Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, 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 (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and 2) 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 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 in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. 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 analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates 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	Those additional reserves that analysis of	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus

	geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	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 (P10) 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 economic production from the reservoir by a defined, commercially mature 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 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 mature and economically 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 elevation and there exists the potential for an associated gas cap, Proved Reserves of oil 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.

Table 3: Partial Glossary of Terms Used in PRMS

Term	Definition
1C	Denotes low estimate of Contingent Resources.
2C	Denotes best estimate of Contingent Resources.
3C	Denotes high estimate of Contingent Resources.
1P	Denotes low estimate of Reserves (i.e., Proved Reserves). Equal to P1.
2P	Denotes the best estimate of Reserves. The sum of Proved plus Probable Reserves.
3P	Denotes high estimate of reserves. The sum of Proved plus Probable plus Possible Reserves.
1U	Denotes the unrisked low estimate qualifying as Prospective Resources.
2U	Denotes the unrisked best estimate qualifying as Prospective Resources.
3U	Denotes the unrisked high estimate qualifying as Prospective Resources.

4. Nomenclature

4.1. 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 true vertical depth 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
Ss	sub sea
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

4.2. Resources Categorisation

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

4.3. 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