Evaluation of Hydro-Carbon Resource Volumes

for the Bilabri Field

Nigeria Offshore Licence OML-122

Equator Exploration Limited

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Executive Summary

Equator Exploration Limited ("Equator") has requested Horizon Energy Partners ("HEP") to provide a Best Estimate for the hydrocarbon assets pertaining to the Bilabri Field, situated in Nigeria's Offshore Licence OML-122.

The quantifications presented in this report have been summarised in terms of In-Place Volumes and Recoverable Volumes.

In terms of In-Place Volumes, the Best Estimate is as follows:

Resource	Type	Equator Share	Unrisked (Success) In-Place Volumes		POS	Risked In-Place Volumes	
			100% Field	Equator share		100% Field	Equator share
Bilabri	Oil	60%*	131 MMstb	78 MMstb*	C2: 100% C1: 80%	110 MMstb	66 MMstb*
Bilabri	Gas	40%	917 Bcf	367 Bcf	100%	917 Bcf	367 Bcf

* : as advised by Equator

In terms of Recoverable Volumes, the Best Estimate is as follows:

Resource	Type	Equator Share	Unrisked (Success) Recoverable Volumes		POS	Risked Recoverable Volumes	
			100% Field	Equator share		100% Field	Equator share
Bilabri	Oil	60%*	50 MMstb	30 MMstb*	C2: 100% C1: 80%	42 MMstb	25 MMstb*
Bilabri	Gas	40%	734 Bcf	294 Bcf	100%	734 Bcf	294 Bcf

* : as advised by Equator

The recoverable oil volume from the Bilabri Field is subject to confirmation appraisal drilling, because the oil rim in the C1 Unit has yet to be demonstrated. This is also the reason for the 20% risking of the volumes from the C1 Unit. The C1 Unit represents approximately 79% of the In-Place Oil Volumes.

The Equator share of oil has been assumed as sixty percent as advised by Equator. This percentage was not reconciled by HEP.

No uncertainty range was requested as part of this report.

The quantification of the Bilabri Recoverable Resources is work still in progress, and therefore above numbers reflect HEP's best estimates at this moment in time. They may be subject to change as a result of maturing evaluation or new data becoming available.

Hydrocarbon resources are categorised using the SPE Petroleum Resources Classification System and Definitions.

Whilst this report represents HEP's best professional judgment as an Independent Consultant, its contents should not be considered a guarantee of results.

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Glossary:

Bcf	billion standard cubic feet
CGR	condensate gas ratio
FPSO	Floating Production Storage and Offloading facility
MMscf	million standard cubic feet
MMstb	million stock tank barrels
NAG	non-associated gas, or free gas
POS	possibility of success (chance factor)
Risked Volumes	product of POS and Success Volumes
scf	standard cubic foot (at 60 deg F, 14.696 psi)
stb	stock tank barrel (at 60 deg F, 14.696 psi)
Success Volumes	volumes in case a defined success case will materialise

1 Introduction

Equator Exploration Limited ("Equator") has requested Horizon Energy Partners ("HEP") to provide a Best Estimate of the hydrocarbon assets pertaining to Equator's Bilabri oil and gas discovery, located some 60 km's offshore in 145 m water depth in Nigeria's OML-122, see Figures 1 and 2.

It is currently envisaged that the exploitation of the Bilabri Field will start with an early oil development, followed by the development of the non-associated gas (NAG).

The In-Place and Recoverable Volumes associated with these oil and gas developments have been treated separately, although it is recognised that a degree of inter-action between these developments will be likely. Volumetric estimates originating from both developments have been given a "Maturity" qualifier in order to illustrate where in the asset life-cycle of identification – evaluation - exploration – appraisal – development it is currently placed. The maturity level is defined by the level of overall knowledge of the asset, the confidence that can be placed in calculation of recoverable volumes, and the robustness of a (notional) development plan.

The Equator interest in a Bilabri oil development is defined in the Financial Services Agreement between Equator and PEAK Petroleum, applicable to volumes from within the OML-122 licence boundaries. It uses a sliding scale as a function of a combination of cumulative oil recovery, cost recovery and well count. Equator has advised HEP that the resulting Equator interest, or Equator entitlement share of cost oil plus profit oil, is approximately 60%. Consequently, the Equator share of recovered oil is assumed to be 60% for the purpose of this report. No allowance has been made for the circumstance that part of the recovered oil may originate from outside the licence boundaries.

The Equator interest in a Bilabri gas development is specified as 40% in the Financial services Agreement between Equator and PEAK Petroleum.

All interpretations and conclusions presented here are opinions based on inferences from geological, geophysical, petrophysical, engineering and other data. The raw data have been provided to HEP by or through Equator. Whilst the report represents HEP's best professional judgment as an independent Consultant, its contents should not be considered a guarantee of results.

2 Evaluations

2.1 OML-122 Bilabri Oil

2.1.1. Status

Oil and gas discovery – penetrated by three wells (Bilabri-1, Bilabri-2, Bilabri Deep-1).

Oil proven in C2 Unit. Oil probable but yet to be proven in C1 Unit.

2.1.2. Methodology

Gross Rock Volumes estimated from 3D seismic data, calibrated by well results.

Fluid contacts are known from well data for C2 Unit, inferred for C1 Unit.

Fluid properties are known from sub-surface samples and well test fluids.

Reservoir properties are estimated from open-hole formation logs and well test results.

Recoverable volumes are estimated from calibrated full-field simulation models.

2.1.3. Maturity

High for C2 Unit.

Medium to High for C1 Unit; an oil rim has yet to be demonstrated in this Unit.

2.1.4. Narrative

The Bilabri area is covered with 3D data from 2 seismic surveys, acquired and processed by PGS. Both surveys have been interpreted by HEP, and some additional processing of the seismic data was performed in order to improve its quality. The time to depth conversion has been calibrated against well results. The quality of the 3D seismic data set is regarded as mediocre.

The field consists of a series of stacked reservoirs. The majority of these reservoirs are gas-filled. The C2 Unit, however, has been found to contain a 21 m thick oil rim overlain by a gas cap. The shallower C1 unit was found gas bearing in the intervals drilled by wells Bilabri-1, -2, and –Deep 1. Based on geological arguments, it is expected that this C1 sand also contains an oil rim, underlying the drilled gas column. The presence of oil in the C1 sand is considered to have an 80% chance factor, but still has to be proven by the planned appraisal well Bilabri D2, to be drilled in June 2006. This well is also expected to confirm the structure towards the North Western part of the field.

All three wells drilled to date have been production tested, and showed good to excellent reservoir properties, and excellent fluid properties. No pressure differentials were found between the three wells on any particular horizon, suggesting that initially each reservoir unit has a single pressure regime across the field.

Oil-In-Place volumes have been estimated using industry standard PETREL geological modelling software. The resulting volumes are 27 million stock tank barrels (MMstb) for the C2 Unit, and 104 million stock tank barrels (MMstb) for the C1 Unit **provided** it contains the expected oil rim of 21 metres thickness. It is noted that the thickness of the potential oil rim in the C1 Unit is not necessarily restricted to 21 metres.

Full field reservoir modelling work has been performed using the industry standard Eclipse reservoir simulation software, in order to predict the dynamic behaviour of the field during development, establish a likely range for recoverable oil volumes, gain insight into different subsurface development scenarios, and estimate the number, type and location of required development wells. The results from the various production tests have been incorporated into this modelling as appropriate, and provide important calibration points. The reservoir simulation work is still in progress at the time of writing, but is nearing completion for the C2 Unit.

<u>Mid Case Scenario</u>

The Best Estimate has been calculated from numerical simulation of a deterministic Mid Case Scenario, which is described below.

It is assumed that well Bilabri D2_S1 will confirm the expected 21 m oil column in the C1 reservoir. Hence a joint C1 plus C2 oil development is envisaged, using a leased FPSO with 8 – 10 sub-sea wells. Oil recovery from the C2 will be realised using the suspended Bilabri Deep 1 well plus two horizontal oil producers. Oil recovery from the C1 will be realised by drilling an estimated 5 to 7 (base case: 6) horizontal oil producing wells. The technical feasibility of drilling such wells is considered as proven technology. The associated gas will partly be used for own consumption, the remainder will initially be flared, and subsequently be re-injected into the C1 Unit through the Bilabri Deep 1 well.

Such a combined C1 & C2 development is estimated to recover ca 50 MMstb of oil (100% field volumes). Production life will be 7 – 10 years, depending on facility size.

It is noted that part of the C1 Unit extends into the neighbouring OPL-458 licence. Initial calculations suggest that some 10-15% of the C1 oil recovery will be from outside the OML-122 licence, resulting in a net OML-122 Bilabri oil recovery of 45 MMstb. The C2 oil recovery will be entirely from within the OML-122 licence boundaries.

In terms of SPE Petroleum Resource Classification, the 45 MMstb may be considered as the Proved plus Probable (2P) Oil Reserves to be recovered from the Bilabri Field inside the OML-122 licence boundaries, at the time of writing. The 50 MMstb recoverable oil volume may be considered as the 2P Oil Reserves from the entire field.

2.2 *OML-122 Bilabri Gas*

2.2.1. Status

Oil and gas discovery – penetrated by three wells (Bilabri-1, Bilabri-2, Bilabri Deep-1)

Gas proven in A1, B1, C1, C2, D1/D2 Units. Gas probable in E1 Unit.

2.2.2. Methodology

Gross Rock Volumes estimated from 3D seismic data, calibrated by well results.

Fluid contacts are known from well data or inferred from seismic anomaly maps.

Fluid properties are largely known from sub-surface samples and well test fluids.

Reservoir properties are estimated from open-hole formation logs and well test results.

Recovery factors are estimated from analogues.

2.2.3. Maturity

Medium.

2.2.4. Narrative

The gas-bearing reservoirs in the Bilabri Field are rather well defined, with the exception of the E1 Unit, which was drilled in the Bilabri Deep 1 well but could not be logged due to operational difficulties. Although some structural uncertainty exists due to the quality of the available seismic data, areal field size is relatively confident because of amplitude anomalies that indicate the extent of the hydro-carbon accumulations.

The gas volumes considered here are the Non Associated Gas (NAG) or Free Gas volumes, and are exclusive of gas dissolved in the oil that is contained in the C2 Unit, and expectedly, the C1 Unit. In other words, they represent the expected gas-cap volumes from the C1 and C2 Units, and the sole gas-fill in the other Units.

Volumetric estimates using the Petrel geological modelling software result in a total Gas-In-Place volume of 917 Bcf (100% field). All gas is located inside the OML-122 licence boundaries. Using a reasonable recovery Factor of 80% throughout, this results to a mid-case Recoverable Gas Volume of 734 Bcf. In terms of the SPE Petroleum Resources Classification System and Definitions, these volumes are categorised as <u>Contingent Resources.</u>

In the un-expected case that the C1 Unit does not contain an oil rim, its free gas volumes will increase correspondingly.

The E1 Unit is believed to be gas-bearing, but this has not as yet been proven. Gas-In-Place volume for this Unit is estimated at 200 Bcf, resulting in an additional recoverable gas volume of 160 Bcf. This volume is presently categorised as Prospective Resources until more reservoir and fluid information is available.

It is envisaged that the Bilabri gas volumes will be recovered subsequent to the Bilabri oil development, using a fixed wellhead tower for tender assisted drilling, bridge-linked to a small production platform. A flat production plateau of 200 MMscf/d will be maintained for 10 years, by initially having five (near-)vertical production wells, supplemented by three re-completions in later field life.

Assuming an average weighted condensate gas ratio (CGR) of 30 stb/MMscf, the In-Place condensate volume amounts to 22 MMstb for Units A1 – D2. The commercial value, and therefore Resource classification, of this condensate volume is dependent on the chosen development option for the Bilabri gas.