COMPETENT PERSON'S REPORT OF CERTAIN PROPERTIES IN PUNTLAND, SOMALIA AS AT 31st DECEMBER, 2010

Prepared for

RED EMPEROR RESOURCES NL

MAY, 2011

The Americas

1300 Post Oak Blvd.,
Suite 1000
Houston, Texas 77056
Tel: +1 713 850 9955
Fax: +1 713 850-9966
email: gcah@gaffney-cline.com

Europe, Africa, FSU and the Middle East

Bentley Hall, Blacknest
Alton, Hampshire
United Kingdom GU34 4PU
Tel: +44 1420 525366
Fax: +44 1420 525367
email: gcauk@gaffney-cline.com

Asia Pacific

80 Anson Road
31-01C Fuji-Xerox Towers
Singapore 079907
Tel: +65 6225 6951
Fax: +65 6224 0842
email: gcas@gaffney-cline.com

and at Argentina - Brazil - Kazakhstan - Russia - UAE - Australia
www.gaffney-cline.com

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Gaffney, Cline & Associates Ltd
Technical and Management Advisers to the Petroleum Industry Internationally Since 1962

Registered London No. 1122740

Bentley Hall
Blacknest, Alton
Hampshire GU34 4PU
United Kingdom

Telephone: +44 (0) 1420 525366
Facsimile: +44 (0) 1420 525367

email: gcauk@gaffney-cline.com
www.gaffney-cline.com

SCW/EE024990/sf **11th May, 2011**

Mr Greg Bandy,
Managing Director,
Red Emperor Resources NL,
945 Wellington Street,
West Perth WA 6005,
Australia.

Cairn Financial Advisers LLP
61 Cheapside,
London,
EC2V 6AX,
United Kingdom

Dear Sirs,

COMPETENT PERSON'S REPORT
ON CERTAIN PROPERTIES IN PUNTLAND, SOMALIA

Red Emperor Resources NL (RMP) commissioned Gaffney, Cline & Associates (GCA) to undertake a Competent Person's Report (CPR) on the prospects and leads on the Dharoor and Nogal Blocks in Puntland, Somalia (Figure 0.1), operated on behalf of RMP by Africa Oil Corporation (AOC). GCA understands that RMP intends to seek admission of all of its shares on the London Stock Exchange Plc's regulated AIM market. This CPR is intended to be included in the Admission Document in connection with that application. As such this CPR has been written in accordance with the requirements of the AIM Guidance Note for Mining, Oil and Gas Companies, dated June, 2009.

GCA has undertaken an evaluation of the Prospective Resource potential on each of these properties using data and presentations provided by the Operator (AOC), supplemented by public domain data. GCA attended presentations on the blocks at the AOC offices in Calgary, Canada. GCA was provided with SMT Kingdom Suite (Kingdom) seismic interpretation projects and other presentations and their recent reports for most of the blocks being assessed. This forms the basis for the opinions here. In carrying out this review, GCA has relied on the information received from AOC.

Industry Standard abbreviations are contained in the attached Glossary (Appendix I), some or all of which may have been used in this report.

In the preparation of this report, GCA used the Petroleum Resources Management System published by the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) in March, 2007 ("SPE PRMS"). See Appendix II.

Reserves are those quantities of petroleum that are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial and remaining (as of the evaluation date) 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 development and production status. All categories of Reserve volumes must been determined within the context of an economic limit test (pre-tax and exclusive of accumulated depreciation amounts) assessment prior to any Net Present Value analysis.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no evident 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.

Prospective Resources are those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

Prospective Resources include Prospects and Leads. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to the point that they are considered drillable. Leads, on the other hand, are not sufficiently well defined to be drillable, and need further work and/or data. In general, leads are significantly more risky than prospects and therefore are not suitable for explicit quantification.

Prospective Resource volumes are presented as unrisked. It must be appreciated that Prospective Resources are risk assessed only in the context of applying the stated 'Geological Chance of Success', a percentage which pertains to the percentage probability of achieving the status of a Contingent Resource (where the Geological Chance of Success is unity). This dimension of risk assessment does not incorporate the considerations of economic uncertainty and commerciality.

It must be clearly understood that any determination of resources volumes, particularly involving continuing field development, will be subject to significant variations over short periods of time as new information becomes available and perceptions change. Not only are such estimates of Reserves and Contingent and Prospective Resources based on that information which is currently available, but such estimates are also subject to uncertainties inherent in the application of judgmental factors in interpreting such information. Contingent and Prospective Resources quantities should not be confused with those quantities that are associated with Reserves due to the additional risks involved. Those quantities that might actually be recovered may differ significantly from the estimates presented herein. A possibility exists that the accumulations and prospects will not result in successful discovery and development, in which case there could be no positive potential present worth.

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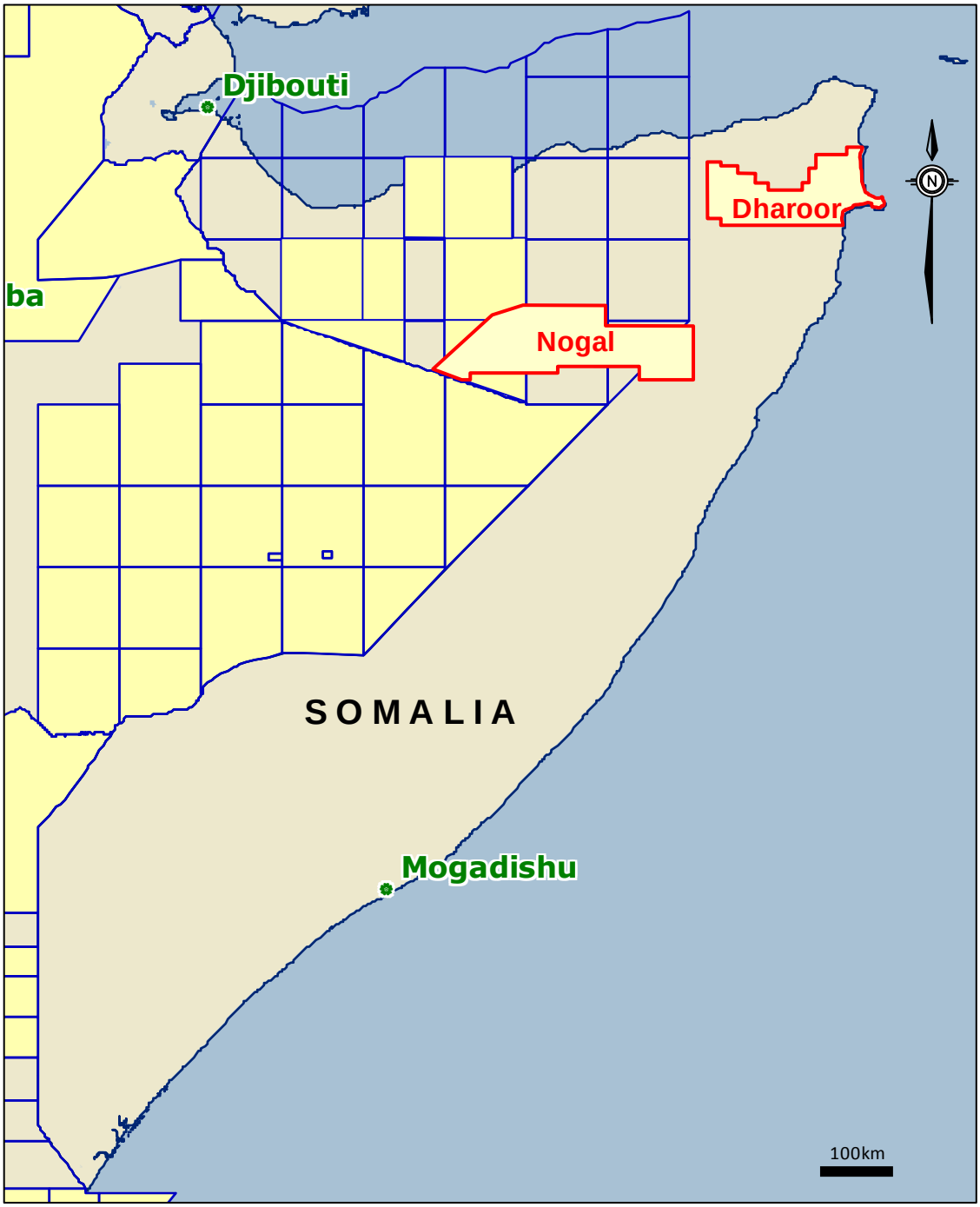
FIGURE 0.1

RMP ACREAGE IN PUNTLAND



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GCA is an energy consultancy specialising in independent petroleum advice on resource evaluation and economic analysis. In preparation of this report, GCA has maintained, and continues to maintain, a strict consultant – client relationship with RMP. The management and employees of GCA have been and continue to be, independent of RMP in the services they provide to the company including the provision of the opinion expressed in this review. Furthermore the management and employees of GCA have no interest in any assets or share capital of RMP or in the promotion of the company.

Opinions concerning sub-surface petroleum resources are associated with considerable uncertainty and represent best estimates based on the data available at the time the opinion is given. The acquisition of new data in the future and/or variations in economic circumstances and market forces may result in significant upward or downward movements in revised total resource estimates.

GCA confirms that, to the best of its knowledge, there has been no material change of circumstances than stated herein.

This Report must only be used for the purpose for which it was intended.

EXECUTIVE SUMMARY

RMP holds working interests in two non-Operated Production Sharing Contracts (PSC's) in Puntland (Somalia) in East Africa. These Blocks are being explored by AOC and its partners and are considered to contain under-explored plays that have proven and productive analogues, and the petroleum system is calibrated by earlier well and seismic data. RMP's Working Interest (WI), Gross and Net acreage is summarised in Table 0.1.

TABLE 0.1

RMP WORKING INTEREST, GROSS AND NET ACREAGE

Blocks	Operator	RMP Net Working Interest (%)	Expiry date	Gross Acreage (km^2)	Net Acreage (km^2)
Nogal Valley	AOC	20	17th January 2012	24,908	4,981.6
Dharoor	AOC	20	17th January 2012	14,424	2,884.8

The Nogal Valley and Dharoor Blocks in Puntland (Somalia) offer the potential to explore in basins that are believed to be analogues of the proven and productive Marib-Shawba and Sayun-Masila Basins of Yemen. The basins in Yemen have been used to calibrate this analysis.

The estimation of Prospective Resource volumes for high-risk and poorly calibrated basins can be subject to large variation from the introduction of new information. The estimates presented in this report are based on all of the information available; however, new data or information is likely to have a material effect on the resource assessment values. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Table 0.2 details the Prospective Resources of RMP in the Puntland Blocks.

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TABLE 0.2

PUNTLAND: SUMMARY OF OIL PROSPECTIVE RESOURCES AS AT 31st DECEMBER, 2010

Licence	Lead	Reservoir	Gross Best Estimate (MMBbl)	RMP Working Interest (%)	Net Best Estimate (MMBbl)	GCoS
Nogal Valley Block	Kalis East	Jesomma	457	20	91.4	0.11
		Gumbero	171	20	34.2	0.09
		Gabredarre	416	20	83.2	0.13
	Kalis South	Jesomma	52	20	10.4	0.08
		Gumbero	28	20	5.6	0.07
		Gabredarre	70	20	14.0	0.09
	Kalis SE	Jesomma	268	20	53.6	0.11
		Gumbero	154	20	30.8	0.09
		Gabredarre	364	20	72.8	0.13
	Kalis SW	Jesomma	83	20	16.6	0.10
		Gumbero	46	20	9.2	0.08
		Gabredarre	113	20	22.6	0.12
	Kalis W	Jesomma	80	20	16.0	0.10
		Gumbero	44	20	8.8	0.08
		Gabredarre	105	20	21.0	0.12
	Nogal SE-A	Jesomma	95	20	19.0	0.11
		Gumbero	53	20	10.6	0.09
		Gabredarre	126	20	25.2	0.13
	Nogal SE-B	Jesomma	57	20	11.4	0.11
		Gumbero	32	20	6.4	0.09
		Gabredarre	77	20	15.4	0.13
	Nogal South	Jesomma	73	20	14.6	0.12
		Gumbero	40	20	8.0	0.10
		Gabredarre	98	20	19.6	0.14
	Nogal-2	Jesomma	73	20	14..6	0.12
		Gumbero	42	20	8.4	0.10
		Gabredarre	130	20	26.0	0.14
	Nogal East	Jesomma	62	20	12.4	0.10
		Gumbero	36	20	7.2	0.08
		Gabredarre	82	20	16.4	0.12
Dharoor Block	Dharoor	Jesomma	299	20	59.8	0.08
		Gumbero	166	20	33.2	0.06
		Gabredarre	440	20	88.0	0.09
	Lead 1	Jesomma	90	20	18.0	0.06
		Gumbero	50	20	10.1	0.05
		Gabredarre	130	20	26.0	0.07
	Lead 2	Jesomma	55	20	11.0	0.06
		Gumbero	30	20	6.0	0.05
		Gabredarre	80	20	16.0	0.07
	Lead 3	Jesomma	36	20	7.2	0.06
		Gumbero	20	20	4.0	0.05
		Gabredarre	55	20	11.0	0.07

Notes:

1. Net Prospective Resources are stated herein in terms of RMP's net Working Interest (WI) in the properties and, due to the very immature nature of these Prospective Resources, have not been computed as net entitlement volumes under the PSA. In this regard these volumes stated herein will exceed the volumes which will arise to RMP under the terms of the PSA.
2. It is inappropriate to report summed-up Prospective Resource volumes or to otherwise focus upon those of other than the 'Best Estimate'.

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3. The Geologic Chance of Success (GCoS) reported here represents an indicative estimate of the probability that the drilling of this prospect would result in a discovery which would warrant the re-categorisation of that volume as a Contingent Resource. These GCoS percentage values have not been arithmetically applied within this assessment.

DISCUSSION

1. REGIONAL GEOLOGICAL SETTING

The Puntland blocks are all located onshore in the north of East Africa (Horn of Africa) (Figure 0.1). The blocks are sparsely explored with only limited well and seismic data available to constrain the petroleum system and prospectivity. However, there are sufficient data on the blocks to demonstrate that a petroleum system is developed within (at least) part of the blocks. This is interpreted to be similar to that seen onshore Yemen. A summary stratigraphy of the basins is shown in Figure 1.1.

The northern part of East Africa was part of the much larger Gondwana mega-continent at the start of the Mesozoic (Figure 1.2). Rifting associated with the northerly drift of this mega-continent and the separation of the continent throughout the Mesozoic (e.g. separation of Australia / India / Africa) led to the development of complex rift geometries across the area. It is within these basins that the Mesozoic petroleum systems developed. Puntland was finally separated from the Arabian Peninsula during the Tertiary opening of the Gulf of Somalia. At this time the Dharoor and Nogal Basins were separated from their analogues in Yemen.

1.1 Common Themes to the Analysis

The Prospective Resources summarised in this report were derived using Monte Carlo volumetric simulation. The inputs for this analysis were obtained from data, reports and independent analysis of the information supplied by the Operator of the PSC's.

When evaluating Prospective Resources, GCA uses a Geological Chance of Success (GCoS) template (Figure 1.3 illustrates one element used) to derive an estimate of the risk associated with Prospective Resources. The use of the template ensures that consistency is maintained between prospects. The template takes into account the amount and quality of information available to be used in the evaluation and also the applicability of these data to resolve the issue. This helps to maintain a consistent GCoS evaluation.

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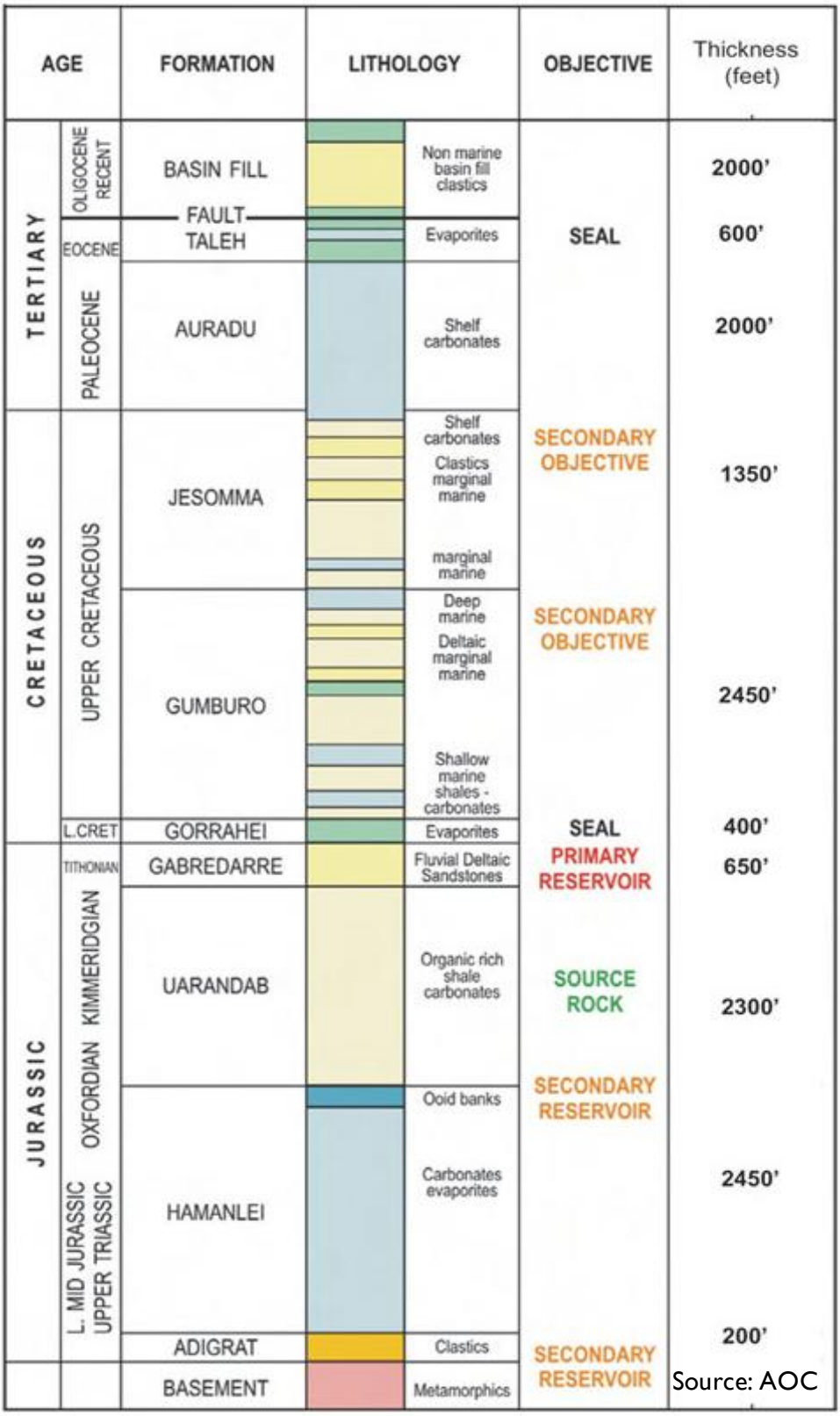
FIGURE 1.1

PUNTLAND STRATIGRAPHIC COLUMN



Source: AOC

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FIGURE 1.2

GONDWANA LATE JURASSIC RECONSTRUCTION

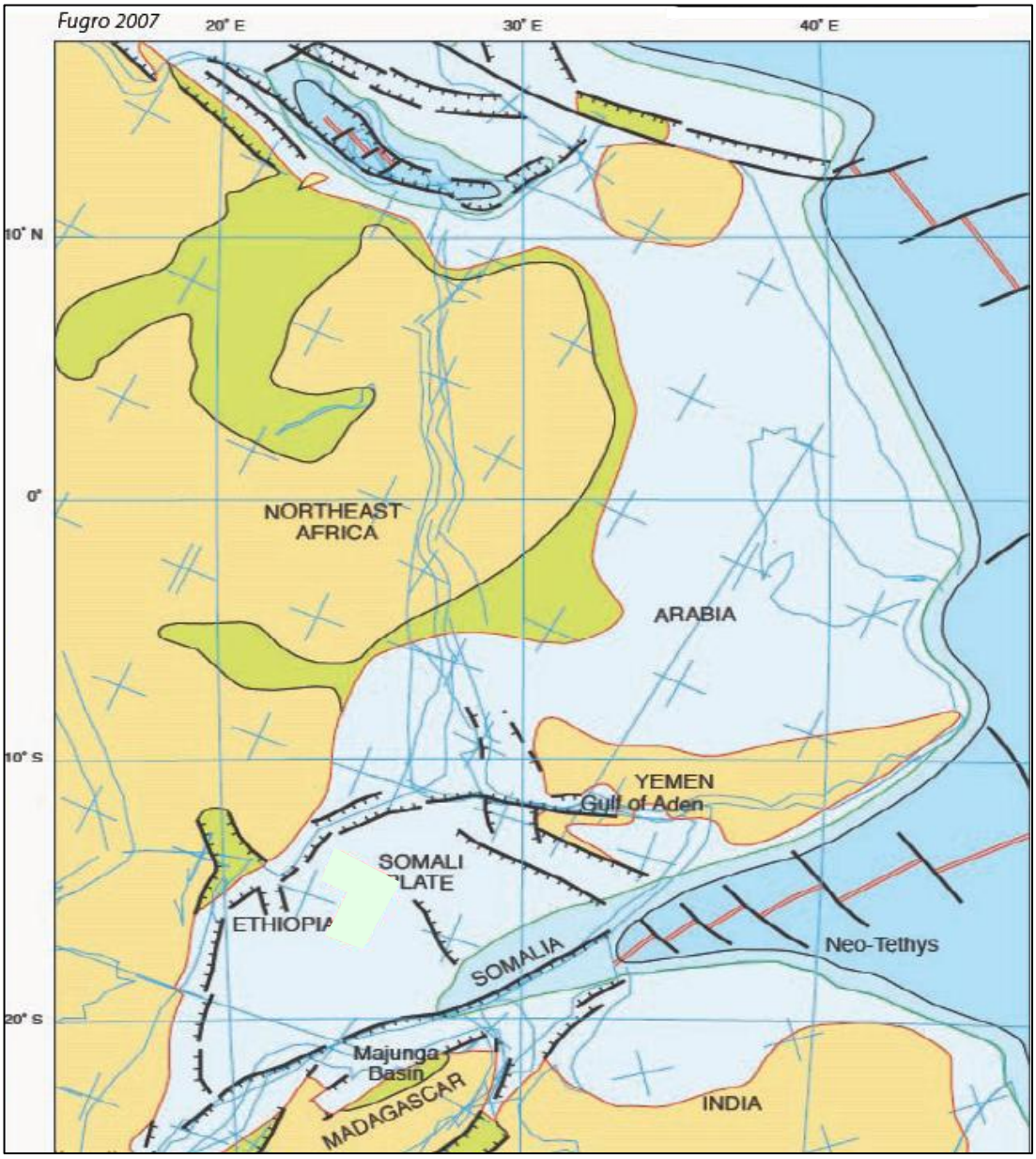

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FIGURE 1.3

GCA GEOLOGICAL CHANCE OF SUCCESS (GCoS) TEMPLATE

Confidence level based on quality and quantity of relevant data

High
- Multiple wells
- Good quality seismic (mainly 3D)
- Petroleum system well understood

Moderate
- Some wells
- Variable quality seismic (mainly 2D)
- Knowledge of petroleum system

Low
- Regional knowledge; trendology
- Evaluation uses analogues

Trap and Seal

Confidence	Low	Moderate	High
High	0.1 – 0.3		0.8 – 1.0*
Moderate	0.2 – 0.3	0.5 – 0.7	0.7 – 0.9
Low	0.3 – 0.4	0.3 – 0.5	0.4 – 0.6

GCOS

Low	Moderate	High
Complex, poorly defined trap, mainly stratigraphic/structural	Moderately complex; mainly structural traps; some stratigraphic component.	Simple, well defined trap, mainly structural.
Thin, discontinuous seal	Thin, continuous seal	Thick, continuous seal
Multiple, intersecting faults – fault leakage	Some fault seal concerns	Simple fault pattern – fault seal

2. SOMALIA (PUNTLAND)

2.1 Overview

RMP has net working interests in Petroleum Sharing Agreements for two exploration blocks onshore northern Somalia (Puntland); the Nogal Valley Block and the Dharoor Block. The location of the two blocks is shown in Figure 0.1 and the RMP net working interest in Table 2.1. The blocks cover the majority of the area of the Nogal Basin and the Dharoor Basin.

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TABLE 2.1

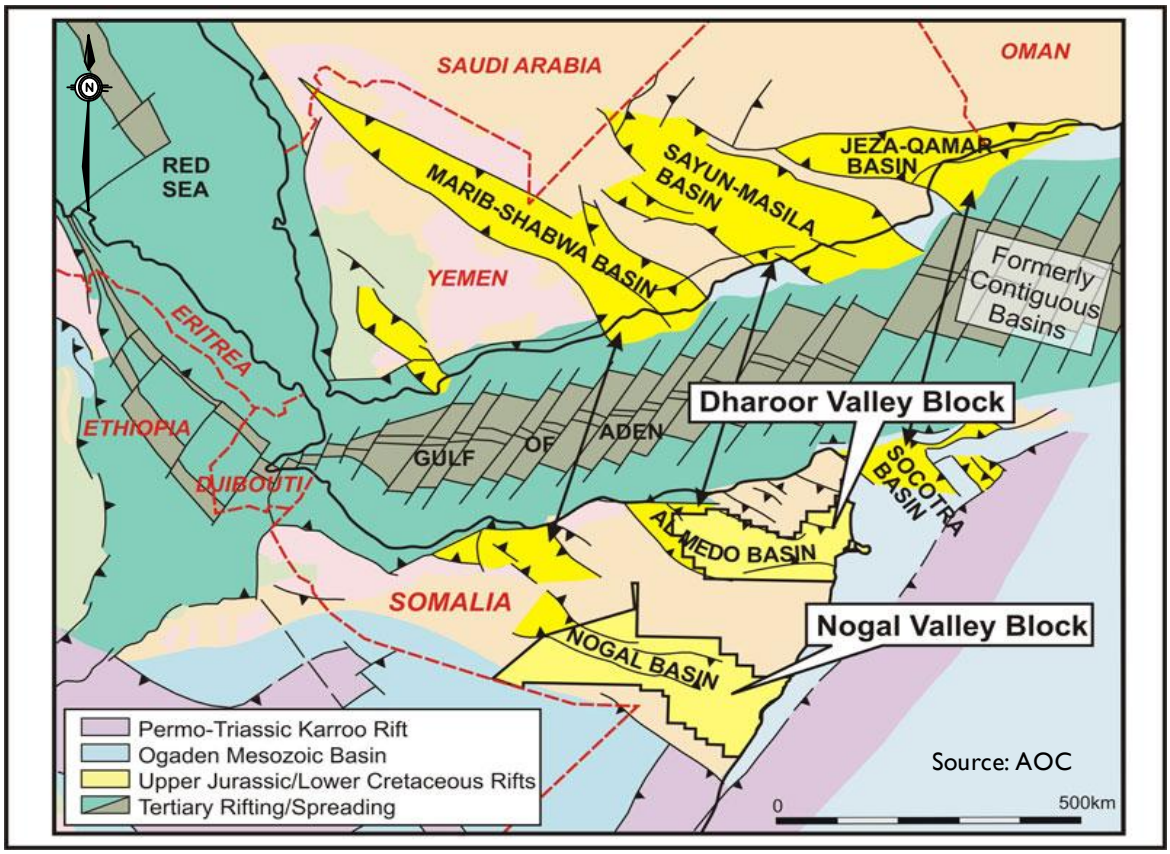
SOMALIA (PUNTLAND)
RMP BLOCKS AND WORKING INTEREST

Puntland Blocks	RMP Working Interest (%)
Nogal Valley (Operator)	20
Dharoor (Operator)	20

The Nogal and Dharoor Basins are part of the larger Mesozoic rift and platforms that developed over the East Africa and the adjacent Arabian Plates during the Mesozoic. These basins developed in response to the break-up of Gondwana and the separation of the continental blocks (Figure 2.1). The Nogal and Dharoor Basins reflect this evolution and Figure 1.1 shows a schematic stratigraphy for the basins. Many of the formation names are similar to those found in the Ogaden Basin, reflecting in part, the common geology.

FIGURE 2.1

SOMALIA: PUNTLAND – SOMALIA AND GULF OF ADEN



2.2 Previous Exploration (Well Review)

Well data are summarised in the Harms & Brady (1989) report "Oil and Gas Potential of the Somali Democratic Republic". This details the history of the wells and provides insight into the results of each well.

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Nogal-1 (Conoco, 1989) provides control in the deeper part of the rift axis with a TD of 3,272 m (10,736 ft). The well did not reach the Jurassic objective, and shows in Cretaceous sandstones were logged but not tested.

Kalis-1 (Conoco, 1990) TD'd at 2,953 m (9,688 ft). The well failed to encounter significant hydrocarbon bearing reservoirs although live oil was described on the mudlog.

Darin-1 (AGIP, 1959) TD'd at 2,966 m (9,730 ft) and recorded oil and gas shows. The Upper Jurassic Gabredarre and Urandab Formations are missing from the well.

Burhisso-1 (Concordia, 1958) was drilled on the margins of the basin.

Las Anod-1 (Concordia, 1957) no data.

Yaguri-1 (Concordia, 1958) no data.

Hordio-1 (Agip, 1959) TD'd at 3486 m (11,206 ft) and recorded gas shows.

Buran-1 (Concordia, 1958) TD'd at 2,430 m (7,994 ft) and was dry. The Upper Jurassic Gabredarre and Urandab Formations were absent.

2.2.1 Seismic Data

Conoco acquired 4,500 km of 60 fold vibroseis data in the late 1980's on the Nogal Block. These data are fair to good quality, sufficient to define large structures. This dataset provides the basis of the seismic interpretation in the Nogal Block.

On the Dharoor Block 550 line km of seismic data were shot in 1975. These data are generally poor quality, but confirm the presence of the Dharoor Basin. In 2008, the Operator (AOC) acquired an additional 782 km of vibroseis data. These data consisted of 15 lines and infill and supplement the earlier data.

2.2.2 Gravity and Magnetic Data

Cities Services acquired surface gravity and magnetic data in 1975. These data partially cover the Blocks, however; confirm the presence of basinal areas in the Blocks.

2.3 Petroleum Systems and Plays

The Mesozoic basins of northern Somalia are interpreted to be extensions of the Marib-Shawba and Sayun-Masila Basins of Yemen. Prior to the opening of the Gulf of Aden in the Oligocene – Miocene these areas were contiguous and similar sedimentary sequences and structural styles are likely (Figure 2.1). This allows the better understood basins of Yemen to be analogues for the Somalia Basins and to constrain the likely hydrocarbon prospectivity of these basins (Figure 2.2).

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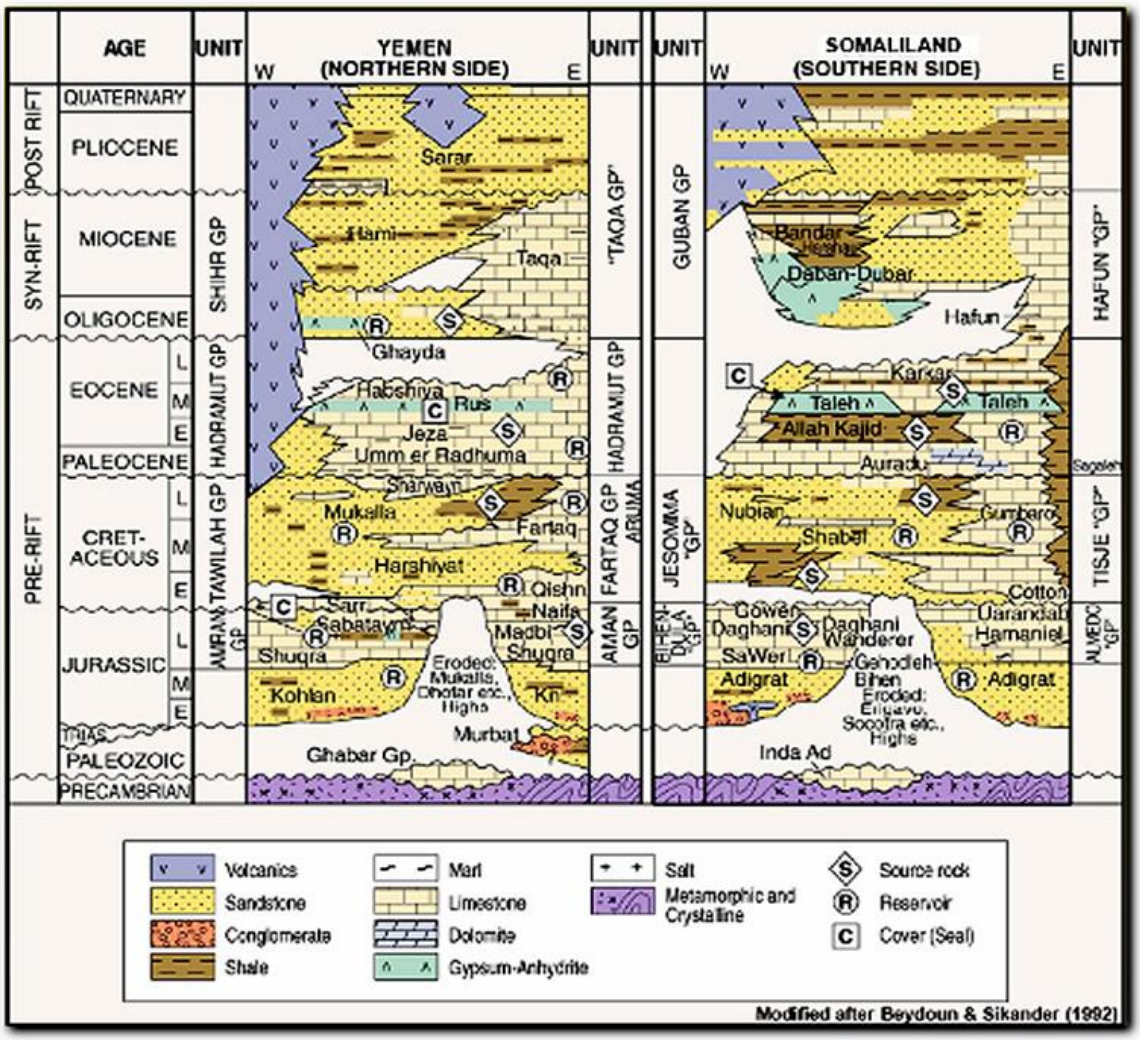
FIGURE 2.2

SOMALIA: COMPARISON OF YEMENI AND SOMALI CHRONOSTRATIGRAPHY



The Nogal and Dharoor Basins are under-explored, and predicting the presence and distribution of potential reservoirs, source rocks and sealing lithologies is problematic. However, based on the available well data and regional knowledge it is possible to predict the horizons most likely to be effective.

2.3.1 Reservoirs

The Adigrat Formation is a basal formation of the Mesozoic megasequence and thickness and quality is likely to be highly variable across the basin. Two onshore wells, Dagah Shabel-2 and Biyo Dader-1, penetrated 191 m and 160 m of sandstones in the Adigrat Formation. Porosity of the sandstones is variable, but values as high as 15% have been reported. However, across the PSC's the Adigrat is buried too deeply to be considered an effective or potentially commercial reservoir.

The Middle-Upper Jurassic carbonates of the Hamanlei Formation have good reservoir potential. The limited data suggests that both limestones and dolomites are developed, with the dolomites having the better reservoir potential.

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The Gabredarre Formation may be absent across large parts of the area due to local non-depositon and erosion across local highs. The Gumbero Formation is shale dominated and contains only thin sandstones.

The Upper Cretaceous Jesomma Formation is a good clastic reservoir. Dagah Shabel-1 well intersected very thick (790 m) fine to coarse-graded fluvial sands of the Nubian (Jesomma) Formation. The well encountered two highly porous sand units where small quantities (4 Bbl) of good quality (33.6° API) oil were recovered.

2.3.2 Seals

The Gumbero Formation is a thick shale that could provide a good top seal to underlying reservoirs. Limited drilling data indicates that this shale may in places be over-pressured further enhancing its sealing capacity. Top seal is also provided by the intraformational shales and evaporites. Lateral seal is by cross-fault seal which in places may limit the vertical column due to reservoir on reservoir juxtaposition.

2.3.3 Source Rocks

The Jurassic Uarandab Formation is the principal source rock for the area. Additional source rocks may be present in the Cretaceous section, however, it is likely that these will be thermally immature for the generation and expulsion of hydrocarbons. The Triassic may contain some source rocks, but kerogen composition and potential thermal maturity indicate that these source rocks are most likely to have generated and expelled gas.

Numerous excellent quality source rocks of Jurassic age are known in outcrops along the coastal margin. Gahodleh and Daghani shales are the most important source rocks in the area. The shales are dark to medium gray kerogen-rich fossiliferous claystones that have fine texture. Shales have played an important part in the generation of hydrocarbon in the area. The 28 Bbl of 32.2° API oil recovered from the Wanderer limestone in the Dagah Shabel-1 well supports this suggestion. Offshore wells have also indicated good source rocks of Jurassic age. For example, Dab Qua-1 well intersected shales of Daghani Formation that had TOCs in the range of 0.53-1.18%.

Upper Cretaceous shales of Jesomma Formation contain fair to good source potential. In both the Bandar Harshau-1and Dab Qua-1 wells, shales in the Jesomma Formation had shown good source potential with TOC up to 5%.

2.3.4 Trap Types

The Operator has mapped the available seismic data in the Nogal and Dharoor Basins. The interpretation supports and confirms the presence of these basins and indicates that the most-likely trap type is the high-side fault bounded trap where cross-fault sealing will be the limiting factor to trap volume.

There is no evidence of large-scale compressional folding like that seen in north-eastern Arabia. Minor folds are known to occur which are believed to have been caused either by rejuvenation of old fault blocks or drag along major faults parallel to the Gulf of Aden.

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2.4 Prospective Resource Evaluation

2.4.1 Kalis Well Cluster (Figure 2.3)

Initial seismic mapping in the area of the Kalis-1 well has identified a number of fault bounded leads that are structurally similar to the feature tested by the Kalis-1 well. These are considered as a cluster, the "Kalis Cluster".

The Kalis cluster is a series of fault bounded terraces oriented along essentially west – east trending faults. The larger leads (e.g Kalis East and Kalis Main) require multiple sealing faults for trapping. Further seismic data will be required to constrain fully the trapping geometry of these leads. Potential reservoirs exist in the Jessoma, Gumbero and Gabredarre Formations. Live oil has been reported from the Kalis-1 well, however, the well failed to identify potentially commercial hydrocarbons.

GCA has estimated In-Place and Prospective Resource estimates for the cluster based in the initial seismic mapping at all three reservoir horizons (Tables 2.2, and 2.3). There is a range of potential volumes at each reservoir level that reflects the uncertainty associated with the trap at that level (size of closure, reservoir thickness etc). At any location it is unlikely that all three reservoirs will be equally successful. The geological chance of success factors for these reservoirs is discussed later.

Kalis Main has already been tested by the Kalis-1 well. The well found potential reservoirs and sealing lithologies and oil and gas shows were reported whilst drilling. The well tested a large rotated fault-block. Cross-fault sealing is required to develop a large closure. Well failure is attributed to cross-fault seal failure and this has a negative impact on the geological chance of success at the analogue leads. No Prospective Resources are reported here.

Kalis East is a large fault block. As with Kalis Main several faults are required to seal to generate a significant closure. As mapped the area of closure is poorly constrained to the west. This feature is the largest undrilled structure in the cluster and has the potential for reservoirs to be developed at all three main levels.

Kalis SE is another large fault bounded closure. Cross-fault seal is required to develop the closure as shown on Figure 2.3. The lead is mapped on 4 seismic dip lines and 1 cross-line. Additional data will be required to confirm the size and presence of the lead.

Kalis South, Kalis W and Kalis SW and smaller leads located to the south of the Kalis-1 well. They are constrained by 1 to 3 seismic lines and are considered small high risk features.

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FIGURE 2.3

SOMALIA: KALIS CLUSTER LEADS

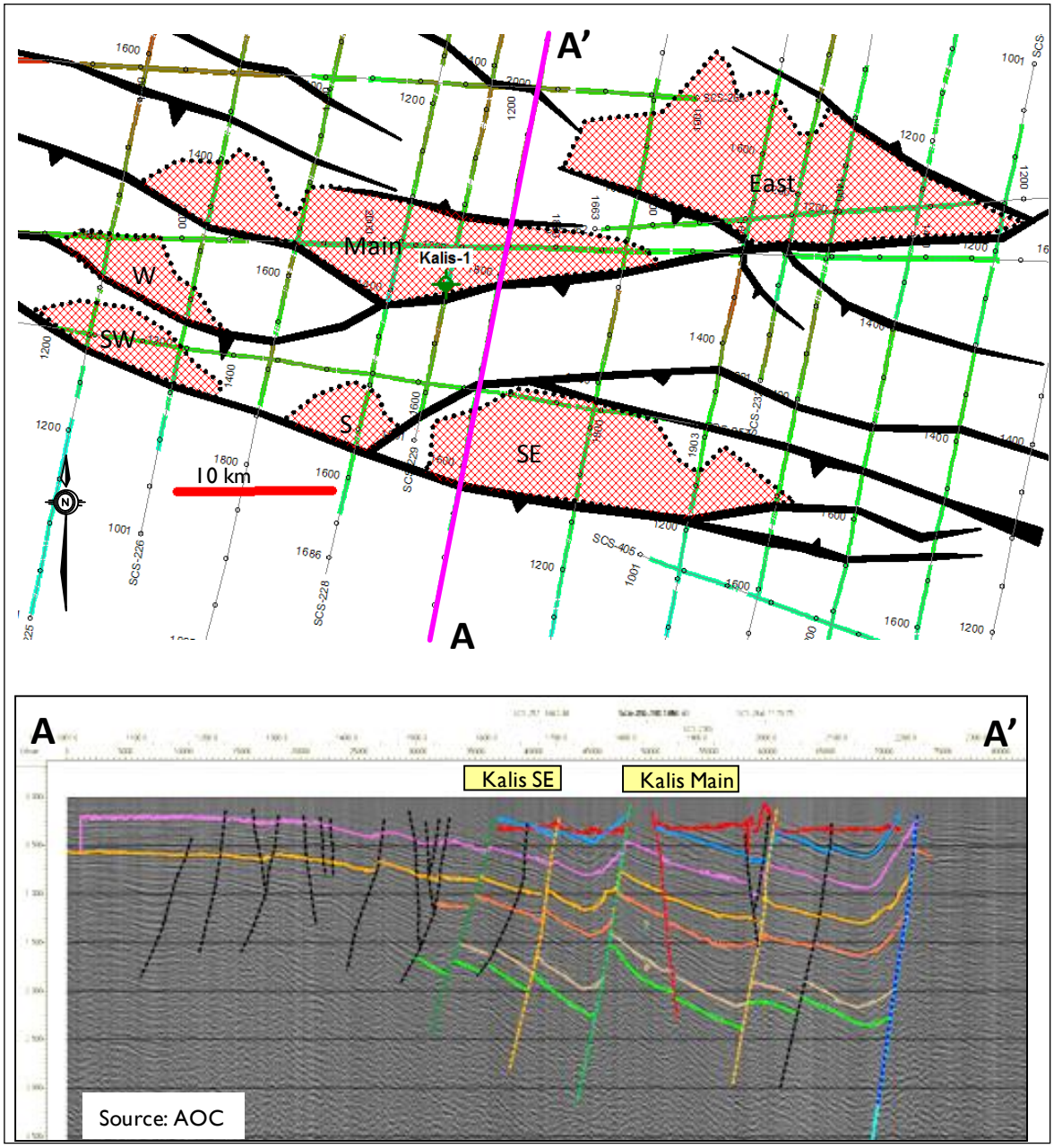

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TABLE 2.2

PUNTLAND
SUMMARY OF OIL IN-PLACE ESTIMATES

Licence	Lead	Reservoir	Gross Best Estimate (MMBbl)
Nogal Valley Block	Kalis East	Jesomma	1,830
		Gumbero	681
		Gabredarre	1,663
	Kalis South	Jesomma	207
		Gumbero	114
		Gabredarre	278
	Kalis SE	Jesomma	1,079
		Gumbero	611
		Gabredarre	1,457
	Kalis SW	Jesomma	330
		Gumbero	184
		Gabredarre	453
	Kalis W	Jesomma	319
		Gumbero	176
		Gabredarre	421
	Nogal SE-A	Jesomma	378
		Gumbero	210
		Gabredarre	507
	Nogal SE-B	Jesomma	227
		Gumbero	126
		Gabredarre	308
	Nogal South	Jesomma	293
		Gumbero	162
		Gabredarre	391
	Nogal – 2	Jesomma	315
		Gumbero	183
		Gabredarre	448
	Nogal East	Jesomma	270
		Gumbero	156
		Gabredarre	356
Dharoor Block	Dharoor	Jesomma	1,196
		Gumbero	664
		Gabredarre	1,760
	Lead 1	Jesomma	360
		Gumbero	200
		Gabredarre	520
	Lead 2	Jesomma	220
		Gumbero	120
		Gabredarre	320
	Lead 3	Jesomma	144
		Gumbero	80
		Gabredarre	220

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TABLE 2.3

PUNTLAND
SUMMARY OF OIL PROSPECTIVE RESOURCE ESTIMATES
AS AT 31st DECEMBER, 2010

Licence	Lead	Reservoir	Gross Best Estimate (MMBbl)	RMP Working Interest (%)	Net Best Estimate (MMBbl)	GCoS
Nogal Valley Block	Kalis East	Jesomma	457	20	91.4	0.11
		Gumbero	171	20	34.2	0.09
		Gabredarre	416	20	83.2	0.13
	Kalis South	Jesomma	52	20	10.4	0.08
		Gumbero	28	20	5.6	0.07
		Gabredarre	70	20	14.0	0.09
	Kalis SE	Jesomma	268	20	53.6	0.11
		Gumbero	154	20	30.8	0.09
		Gabredarre	364	20	72.8	0.13
	Kalis SW	Jesomma	83	20	16.6	0.10
		Gumbero	46	20	9.2	0.08
		Gabredarre	113	20	22.6	0.12
	Kalis West	Jesomma	80	20	16.0	0.10
		Gumbero	44	20	8.8	0.08
		Gabredarre	105	20	21.0	0.12
	Nogal SE-A	Jesomma	95	20	19.0	0.11
		Gumbero	53	20	10.6	0.09
		Gabredarre	126	20	25.2	0.13
	Nogal SE-B	Jesomma	57	20	11.4	0.11
		Gumbero	32	20	6.4	0.09
		Gabredarre	77	20	15.4	0.13
	Nogal South	Jesomma	73	20	14.6	0.12
		Gumbero	40	20	8.0	0.10
		Gabredarre	98	20	19.6	0.14
	Nogal-2	Jesomma	73	20	14..6	0.12
		Gumbero	42	20	8.4	0.10
		Gabredarre	130	20	26.0	0.14
	Nogal East	Jesomma	62	20	12.4	0.10
		Gumbero	36	20	7.2	0.08
		Gabredarre	82	20	16.4	0.12
Dharoor Block	Dharoor	Jesomma	299	20	59.8	0.08
		Gumbero	166	20	33.2	0.06
		Gabredarre	440	20	88.0	0.09
	Lead 1	Jesomma	90	20	18.0	0.06
		Gumbero	50	20	10.1	0.05
		Gabredarre	130	20	26.0	0.07
	Lead 2	Jesomma	55	20	11.0	0.06
		Gumbero	30	20	6.0	0.05
		Gabredarre	80	20	16.0	0.07
	Lead 3	Jesomma	36	20	7.2	0.06
		Gumbero	20	20	4.0	0.05
		Gabredarre	55	20	11.0	0.07

Notes:

1. Net Prospective Resources are stated herein in terms of RMP's net Working Interest (WI) in the properties and, due to the very immature nature of these Prospective Resources, have not been computed as net entitlement volumes under the PSC. In this regard these volumes stated herein will exceed the volumes which will arise to RMP under the terms of the PSC.

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2. It is inappropriate to report summed-up Prospective Resource volumes or to otherwise focus upon those of other than the 'Best Estimate'.
3. The Geologic Chance of Success (GCoS) reported here represents an indicative estimate of the probability that the drilling of this prospect would result in a discovery which would warrant the re-categorisation of that volume as a Contingent Resource. These GCoS percentage values have not been arithmetically applied within this assessment.

2.4.2 Stacked Plays and Pays

In the Nogal Valley and Dharoor Blocks the understanding of the petroleum system and stratigraphy is immature due to the lack of data. The petroleum system of the Shawba and Masila Basins of Yemen has been proposed as an analogue for these basins. In these basins several reservoirs have been proven to be productive, however, in general only one reservoir has proved to be commercially productive per discovery. The same is likely to be true in the Somali Basins where several potential plays and pays have been identified. GCA believes that it is likely that only 1 reservoir per target is likely to be significant. At present, with the current dataset it is not possible to be sure which horizon this is likely to be (in fact, the main reservoir may not yet be identified).

In the three plays volumetrically evaluated; the Jesomma, Gumbero and Gabredarre Formations the Gabredarre is interpreted to have the highest geological chance of success in the Nogal Valley Block, with the other reservoirs being less likely. In the Dharorr Block a Cretaceous reservoir is more likely. However, it must be stressed that additional data may lead to this interpretation requiring re-evaluation.

Therefore, for any of the leads identified it is likely that only 1 reservoir zone will be ultimately effective, and that the aggregation of multiple play (or pays) should not be done.

2.4.3 Nogal Well Cluster (Figure 2.4)

The new seismic shot in the area of the Nogal-1 well has defined a number of fault bounded closures. These are structurally similar but smaller to the closure tested by the Nogal-1 well.

All of the leads are high fault traps that require cross-fault sealing for a significant area of closure to develop. Given the seismic line spacing and the uncertainty about the stratigraphy a wide range of possible closure areas are modelled in the volumetrics.

There is still a small potential attic volume remaining up-dip of the Nogal-1 well. Initial mapping indicates that the well was located off the crest of the closure. The size of the accumulation depends on cross-fault seal. The Operator is currently remapping in the area and this may result in a re-definition of the clusters potential.

Nogal South lies across a fault from Nogal-1 and was identified in earlier evaluations. The trap relies on cross-fault seal and is moderately well defined on the current seismic dataset.

Nogal-2 lead lies along strike from Nogal South and relies on the same fault to define the trap. A subsidiary fault separates this lead from Nogal-E. These leads have similar risk (GCoS) profiles and they exhibit a high degree of dependency.

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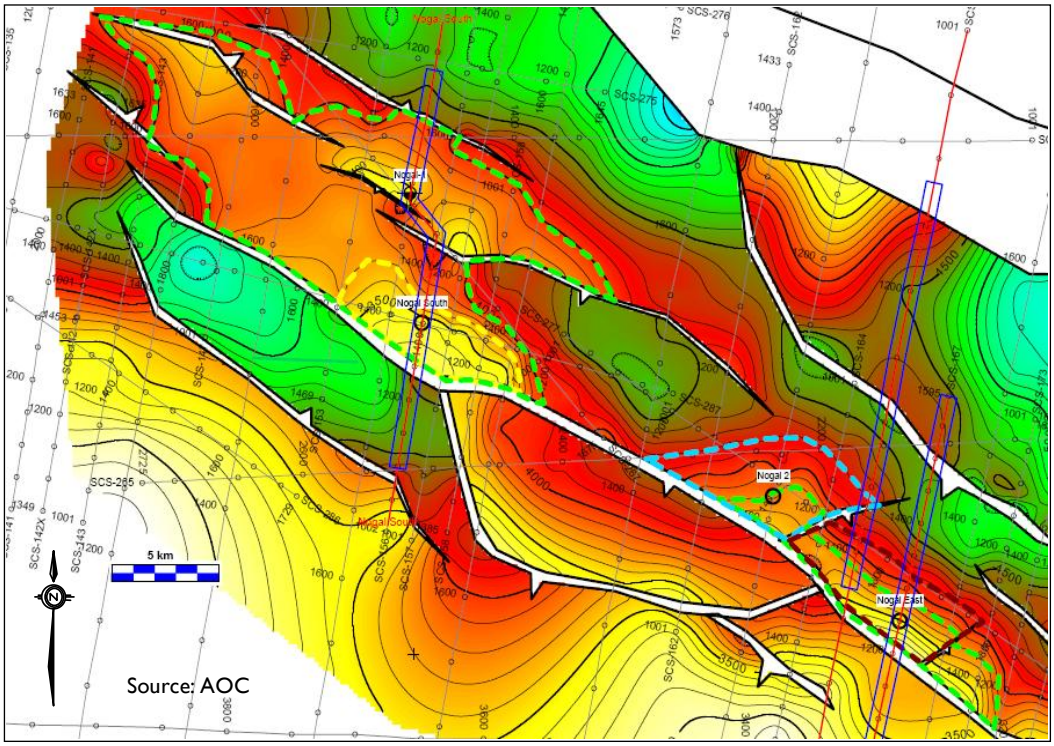
FIGURE 2.4

SOMALIA: NOGAL CLUSTER LEADS



2.4.4 Dharoor Block

AOC has completed initial mapping of the seismic dataset in the Dharoor Block. New seismic data were acquired in 2008 and these data infill the existing data (Figure 2.5). However, even with the new seismic data the survey has a line spacing of 4 to 5 km. Re-interpretation of these data is ongoing (in 2011) and may result in the re-definition of the potential of the block.

The initial mapping identified several fault bounded features similar to those mapped at the Nogal and Kalis clusters. Well data from the block indicates that the stratigraphy expected in the block is similar to that seen in the Nogal Basin. Therefore, it is likely that similar reservoirs will be developed, and that cross-fault sealing will be the critical factor in trap size and definition.

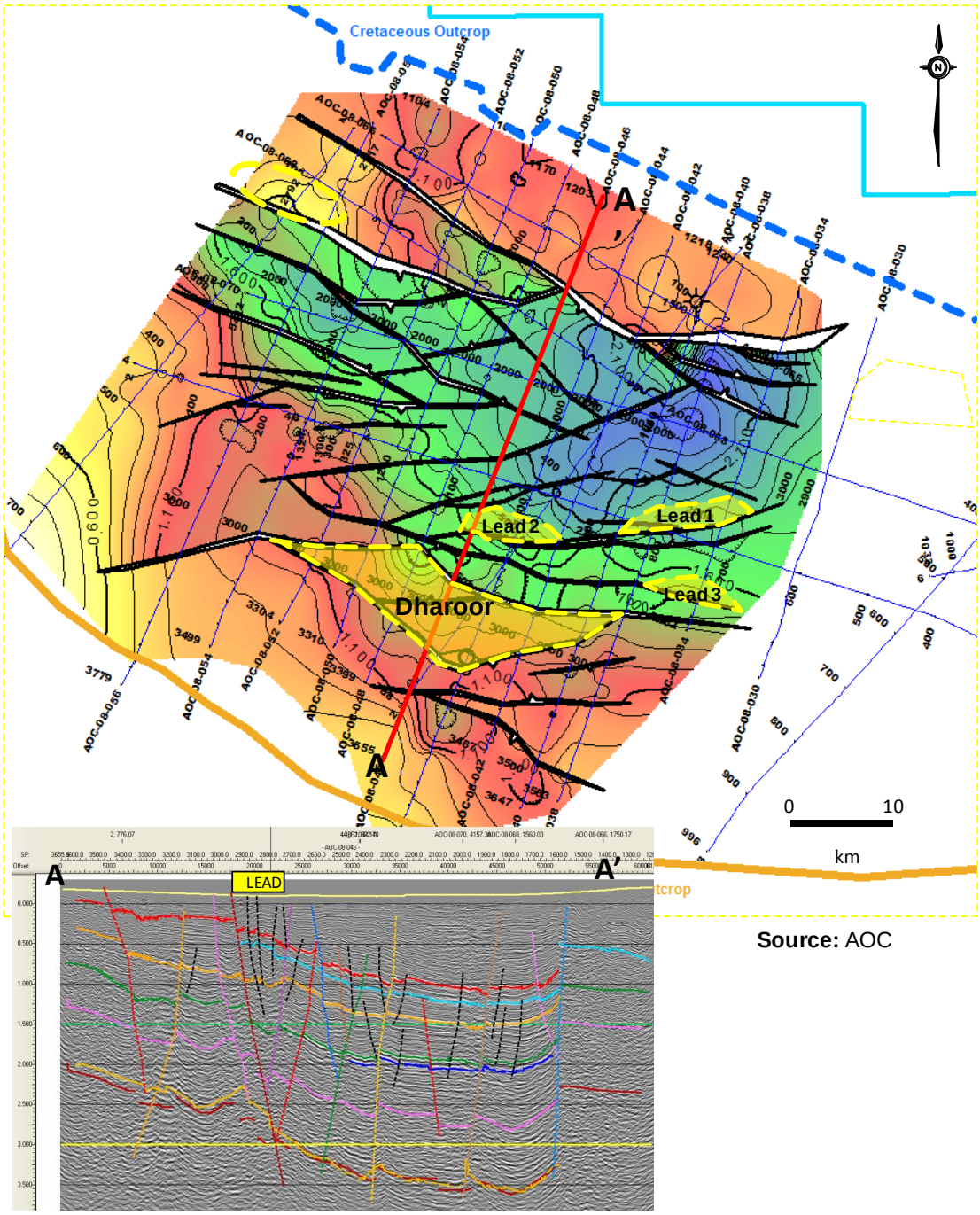
The initial mapping has defined several fault bounded structures, all requiring sealing faults to work to develop significant sized traps. Prospectivity has been mainly identified in the south and east of the mapped area (Figure 2.5). Given the seismic data density in the area and problems of fault correlation in such data scarce areas prospect definition is problematic. However, these data allow the Dharoor lead to be mapped with a maximum closure of 128 km^2. In addition to this trap, three additional leads have also been identified with areas ranging from 10 to 20 km^2.

Further seismic data will be required to mature the Dharoor lead and other leads, and to identify additional potential. These additional seismic data may lead to the prospect being segmented into a number of clustered leads as seen at Nogal and Kalis. This is particularly the case for the Dharoor lead which with the current seismic data already

consists of two segments. Seismic data density and quality at the Dharoor lead is limited and the interpretation of seismic reflectors is not simple. Given the requirement of cross-fault sealing to work in this type of structure (as seen in the analogue basins in Yemen) it is likely that the reservoirs will not be filled to structural spill. However, given the lack of detailed knowledge of the stratigraphy of the lead the volume estimates provided are considered to be reasonable.

FIGURE 2.5

SOMALIA: DHAROOR CLUSTER LEADS



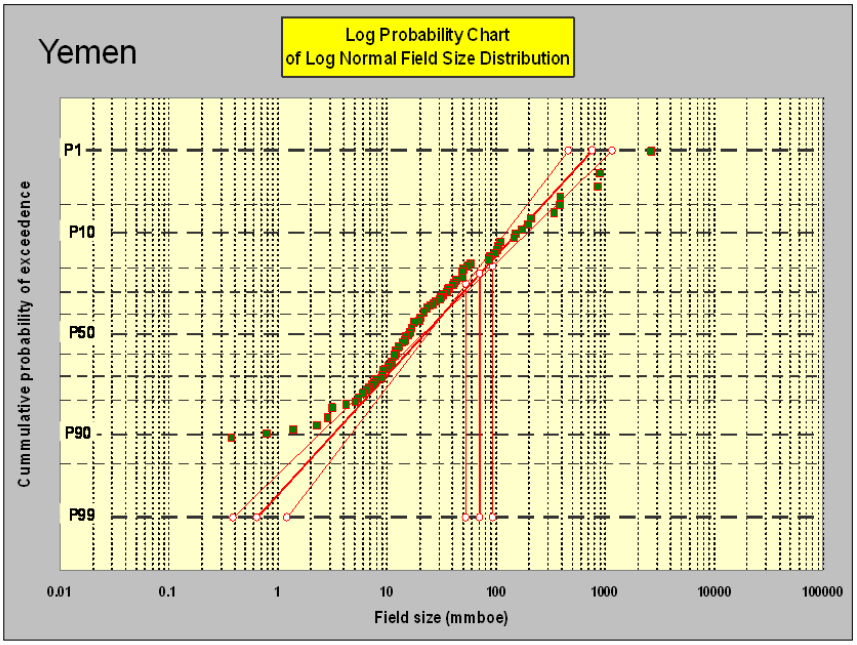
Source: AOC

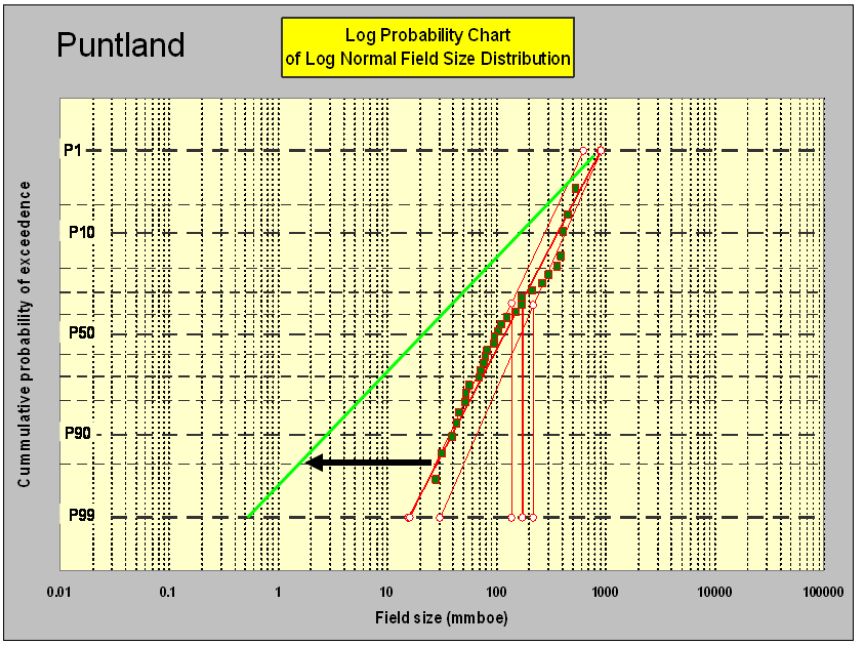
2.4.5 Comparison with the Onshore Basins of Yemen

The Nogal and Dharoor Basins are interpreted to be extensions of the Marib-Shabwa and Sayun-Masila Basins of Yemen (Figure 2.1) which now are separated by the Late Cenozoic opening of the Gulf of Aden. The fieldsize distribution (FSD) from Yemen can be used as an analogue for the Somali Basins. Based on published data, a FSD plot for the Yemeni Basins was generated and this was compared to the FSD based on the leads and prospects currently mapped in the Nogal and Dharoor Basins (Figure 2.6).

FIGURE 2.6

FIELDSIZE DISTRIBUTION COMPARISON YEMEN AND PUNTLAND





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This shows that the maximum field size predicted for the Nogal and Dharoor Basins (c. 900 MMBbl) is larger than in the Yemen onshore (c. 750 MMBbl). The low side estimate for the Somali Basins is also higher than the low-side estimate for Yemen. This causes the mean field size for Somalia (175 MMBbl) to be higher than the Yemen Mean (71 MMBbl). This reflects the immaturity of the analysis of the leads and prospects in the Somali Basins where only the largest features have been identified. It is also possible that these leads will with further analysis become further segmented reducing the size of the potential accumulations.

2.5 Somalia (Puntland) GCoS

In the Kalis and Nogal Clusters the principal risk element is trap integrity with cross-fault seal capacity being the factor controlling trap size and geometry (c.f. Yemen). The acquisition of additional seismic data, and a better understanding of the stratigraphy is required before this factor can be constrained with more certainty.

The secondary chance factor that materially affects GCoS at a lead level is reservoir presence and effectiveness. The distribution and effectiveness of the potential reservoirs in the basin is poorly constrained by the few wells available. However, at present the Gabredarre Formation is believed to have the best potential, with the Jesomma and Gumbero Formations also having resource potential.

The GCoS shown in Table 2.3 is the GCoS value determined for independent leads. This does not take into account the dependency between the leads (e.g. common source rock etc). Success (or failure) at one lead will result in a significant change in the GCoS estimate for the remaining leads (Bayesian update).

In such high risk areas further information can lead to significant changes in the GCoS assessed at both Play and Prospect (lead) level.

QUALIFICATIONS

GCA is an independent international energy advisory group of almost 50 years' standing, whose expertise includes petroleum reservoir evaluation and economic analysis.

The report is based on information compiled by professional Associates of GCA.

Professional Associates who participated in the compilation of this report includes Mr. Brian Rhodes, and Dr Stephen Wright. All hold at least a bachelor's degree in geoscience, petroleum engineering or related discipline. Mr. Rhodes holds a B.Sc. (Hons) Geology, is a member of the Energy Institute, the Petroleum Exploration Society of Great Britain, the Society of Petroleum Engineers and the European Association of Geoscientists and Engineers, and has more than 36 years industry experience. Dr. Wright has more than 25 years of Industry experience holds a B.Sc. (Hons) Geology from Kings College, University of London and a D.Phil from the University of Oxford, he is a fellow of the Geological Society of London and a member of the Petroleum Exploration Society of Great Britain.

BASIS OF OPINION

This assessment has been conducted within the context of GCA's understanding of the effects of petroleum legislation, taxation, and other regulations that currently apply to these properties. However, GCA is not in a position to attest to property title, financial interest relationships or encumbrances thereon for any part of the appraised properties.

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It should be understood that the evaluation of petroleum properties involves judgments in respect of a series of issues and parameters that cannot be measured precisely The opinions expressed herein represent GCA's judgment based upon its evaluation of these issues, the data that has been made available and the company's professional experience in the consideration of these matters. Any evaluation may be subject to significant variation over time as new information becomes available or perceptions of market conditions change.

Yours sincerely
GAFFNEY, CLINE & ASSOCIATES

Brian Rhodes
Principal Advisor

APPENDIX I

Glossary

GLOSSARY

List of Standard Oil Industry Terms and Abbreviations.

ABEX	Abandonment Expenditure
ACQ	Annual Contract Quantity
°API	Degrees API (American Petroleum Institute)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus Offset
A$	Australian Dollars
B	Billion (10^9)
Bbl	Barrels
/Bbl	per barrel
BBbl	Billion Barrels
BHA	Bottom Hole Assembly
BHC	Bottom Hole Compensated
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
Bm^3	Billion cubic metres
bcpd	Barrels of condensate per day
BHP	Bottom Hole Pressure
blpd	Barrels of liquid per day
bpd	Barrels per day
boe	Barrels of oil equivalent @ xxx mcf/bbl
boepd	Barrels of oil equivalent per day @ xxx mcf/bbl
BOP	Blow Out Preventer
bopd	Barrels oil per day
bwpd	Barrels of water per day
BS&W	Bottom sediment and water
BTU	British Thermal Units
bwpd	Barrels water per day
CBM	Coal Bed Methane
CO_2	Carbon Dioxide
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
cm	centimetres
CMM	Coal Mine Methane
CNG	Compressed Natural Gas
Cp	Centipoise (a measure of viscosity)
CSG	Coal Seam Gas
CT	Corporation Tax
DCQ	Daily Contract Quantity
Deg C	Degrees Celsius
Deg F	Degrees Fahrenheit
DHI	Direct Hydrocarbon Indicator
DST	Drill Stem Test
DWT	Dead-weight ton
E&A	Exploration & Appraisal
E&P	Exploration and Production
EBIT	Earnings before Interest and Tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
EI	Entitlement Interest

GLOSSARY (Cont'd.)

EIA	Environmental Impact Assessment
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
EUR	Estimated Ultimate Recovery
FDP	Field Development Plan
FEED	Front End Engineering and Design
FPSO	Floating Production, Storage and Offloading
FSO	Floating Storage and Offloading
ft	Foot/feet
Fx	Foreign Exchange Rate
g	gram
g/cc	grams per cubic centimetre
gal	gallon
gal/d	gallons per day
G&A	General and Administrative costs
GBP	Pounds Sterling
GDT	Gas Down to
GIIP	Gas initially in place
Gj	Gigajoules (one billion Joules)
GOR	Gas Oil Ratio
GTL	Gas to Liquids
GWC	Gas water contact
HDT	Hydrocarbons Down to
HSE	Health, Safety and Environment
HSFO	High Sulphur Fuel Oil
HUT	Hydrocarbons up to
H_2S	Hydrogen Sulphide
IOR	Improved Oil Recovery
IPP	Independent Power Producer
IRR	Internal Rate of Return
J	Joule (Metric measurement of energy) I kilojoule = 0.9478 BTU)
k	Permeability
KB	Kelly Bushing
KJ	Kilojoules (one Thousand Joules)
kl	Kilolitres
km	Kilometres
km^2	Square kilometres
kPa	Thousands of Pascals (measurement of pressure)
KW	Kilowatt
KWh	Kilowatt hour
LKG	Lowest Known Gas
LKH	Lowest Known Hydrocarbons
LKO	Lowest Known Oil
LNG	Liquefied Natural Gas
LoF	Life of Field
LPG	Liquefied Petroleum Gas
LTI	Lost Time Injury
LWD	Logging while drilling
m	Metres
M	Thousand

GLOSSARY (Cont'd.)

m^3	Cubic metres
Mcf or Mscf	Thousand standard cubic feet
MCM	Management Committee Meeting
MMcf or MMscf	Million standard cubic feet
m^3d	Cubic metres per day
mD	Measure of Permeability in millidarcies
MD	Measured Depth
MDT	Modular Dynamic Tester
Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
MFT	Multi Formation Tester
mg/l	milligrames per litre
MJ	Megajoules (One Million Joules)
Mm^3	Thousand Cubic metres
Mm^3d	Thousand Cubic metres per day
MM	Million
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
Mode	Value that exists most frequently in a set of values = most likely
Mscfd	Thousand standard cubic feet per day
MMscfd	Million standard cubic feet per day
MW	Megawatt
MWD	Measuring While Drilling
MWh	Megawatt hour
mya	Million years ago
NGL	Natural Gas Liquids
N_2	Nitrogen
NPV	Net Present Value
OBM	Oil Based Mud
OCM	Operating Committee Meeting
ODT	Oil down to
OPEX	Operating Expenditure
OWC	Oil Water Contact
p.a.	Per annum
Pa	Pascals (metric measurement of pressure)
P&A	Plugged and Abandoned
PDP	Proved Developed Producing
PI	Productivity Index
PJ	Petajoules (10^{15} Joules)
PSDM	Post Stack Depth Migration
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PUD	Proved Undeveloped
PVT	Pressure volume temperature
P10	10% Probability
P50	50% Probability
P90	90% Probability
Rf	Recovery factor
RFT	Repeat Formation Tester

GLOSSARY (Cont'd.)

RT	Rotary Table
R_w	Resistivity of water
SCAL	Special core analysis
cf or scf	Standard Cubic Feet
cfd or scfd	Standard Cubic Feet per day
scf/ton	Standard cubic foot per ton
SL	Straight line (for depreciation)
s_o	Oil Saturation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
ss	Subsea
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
s_w	Water Saturation
T	Tonnes
TD	Total Depth
Te	Tonnes equivalent
THP	Tubing Head Pressure
TJ	Terajoules (10^{12} Joules)
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical Committee Meeting
TOC	Total Organic Carbon
TOP	Take or Pay
Tpd	Tonnes per day
TVD	True Vertical Depth
TVDss	True Vertical Depth Subsea
USGS	United States Geological Survey
U.S.$	United States Dollar
VSP	Vertical Seismic Profiling
WC	Water Cut
WI	Working Interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent
1H05	First half (6 months) of 2005 (example of date)
2Q06	Second quarter (3 months) of 2006 (example of date)
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
%	Percentage

APPENDIX II

SPE PRMS Guide

Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers

Petroleum Resources Management System

Definitions and Guidelines ([1])

March 2007

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 management 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 definition 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 document 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 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 PRMS Definitions and Guidelines can be viewed at:
www.spe.org/specma/binary/files/6859916Petroleum_Resources_Management_System_2007.pdf

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[1] These Definitions and Guidelines are extracted from the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document ("SPE PRMS"), approved in March 2007.

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 5 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.

On Production

The development project is currently producing and selling petroleum to market.

The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

Approved for Development

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

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.

In order 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, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (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.

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:

(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 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. 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

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.

Developed Reserves

Developed Reserves are expected quantities to be recovered from existing wells and facilities.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate but which have not yet started producing,

(2) wells which were shut-in for market conditions or pipeline connections, or

(3) wells not capable of production for mechanical reasons.

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments:

(1) from new wells on undrilled acreage in known accumulations,

(2) from deepening existing wells to a different (but known) reservoir,

(3) from infill wells that will increase recovery, or

(4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to

(a) recomplete an existing well or

(b) install production or transportation facilities for primary or improved recovery projects.

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 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.

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 re-classification 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 Unclarified or 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 eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, 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 Not Viable

A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to 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 any further data acquisition or studies on the project for the foreseeable future.

PROSPECTIVE RESOURCES

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 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 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.

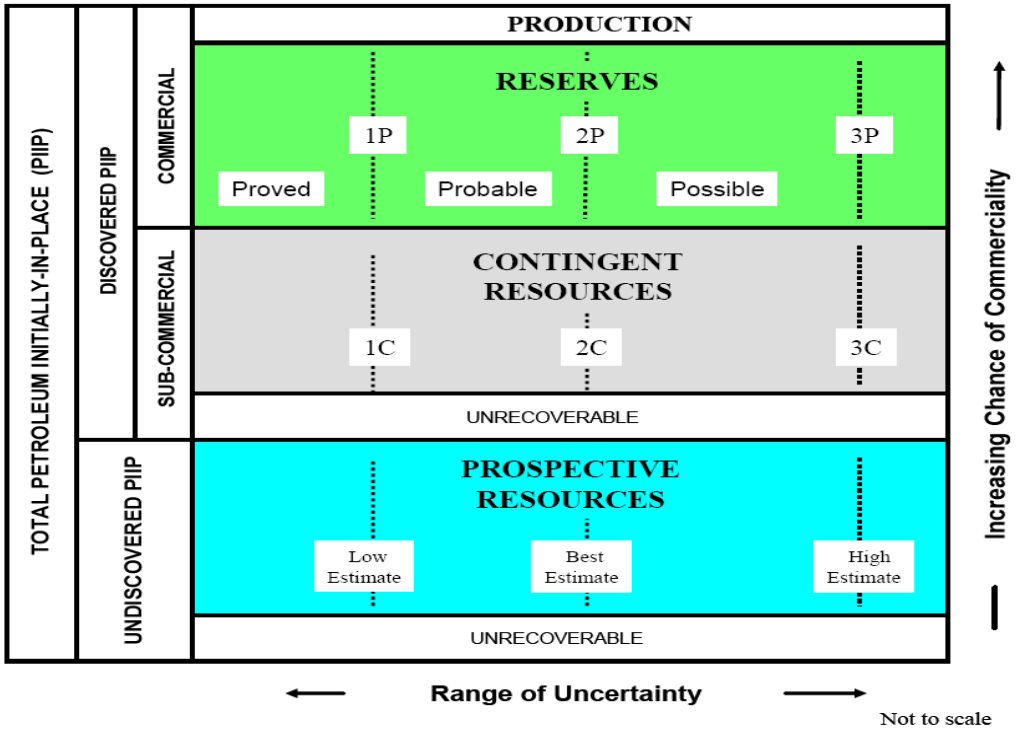
Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under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

RESOURCES CLASSIFICATION



PROJECT MATURITY