Oilfield International

June 29th 2011

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Dear Sirs

COMPETENT PERSONS REPORT ("CPR")
Valuation of the Assets of Neptune Petroleum (Namibia) Ltd

Summary

In accordance with your instructions, Oilfield International ("OIL") has valued the petroleum interests held by Tower Resources Plc through Neptune Petroleum (Namibia) Ltd – ("Tower"), namely a 15% working interest in Namibia Licence 0010. The valuation date is 31st May 2011. We have conducted a detailed review of the "Delta" structure and calculated the EMVs of the prospects and leads we identified. We have also updated the EMVs of two other structures, "Alpha" and "Gamma" which were the subject of our June 2010 CPR on Licence 0010 on behalf of Tower Resources.

The Operator, Arcadia Expro Namibia (PTY) Limited - ("Arcadia") has made available to OIL a recently acquired and processed high quality 3D seismic survey over the primary drilling target, Delta; 2D surveys of various vintages over the whole licence; geophysical and geological data and reports; and licence information. OIL has relied on the completeness and accuracy of this information when preparing this CPR and undertaken independent assessments and validations where judged necessary. OIL has not conducted a site visit because the assets are undeveloped.

OIL conducted its assessment in compliance with the SPE Petroleum Resources Management System (SPE-PRMS) sponsored by the Society of Petroleum Engineers/American Association of Petroleum Geologists/World Petroleum Council/Society of Petroleum Evaluation Engineers (SPE/ AAPG/ WPC/ SPEE) in March 2007. An abbreviated form of the SPE-PRMS definitions and guidelines is presented in Appendix 1. OIL has attributed Prospective Resources to Licence 0010, using the SPE PRMS definition below. OIL has identified no Reserves or Contingent Resources in Licence 0010.

Prospective Resources are those quantities of petroleum 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. The subdivisions are Prospect, Lead and Play:-

- A Prospect is 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.

- A Lead is 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 scenario.

- A Play is 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.

OIL has identified two Prospects, five Leads and three plays in Licence 0010. There are no recoverable reserves or contingent resources in Licence 0010. The assets are all Prospective Resources and are Prospects, Leads and Plays in the Namibe and Walvis Basins.

- The two Prospects are the Delta Maastrichtian and the Delta Palaeocene. Both will be targeted by the first exploration well.
- There are five Leads namely: Delta Upper Campanian, Delta Campanian Wedge, Delta Albian, Alpha Palaeocene and Gamma Palaeocene. The first three are secondary targets for the first exploration well.
- There are three Plays, namely the GE, BA and AG Inter-Structural Areas.
- There are other Plays at early stages of evaluation. These could become more significant in the event of success in the first drilling campaign.

Table 0.1 summarises the licence information for Licence 0010 and Figure 0.1 shows its location offshore Namibia. The water depth of the main leads is in the approximate range 900m to 1300m. The area marked in red is the retained licence, the other 50% was relinquished on renewal of the exploration licence; the area relinquished does not affect any of the Prospective Resources evaluated in this report.

Licence 0010 was granted on 23rd August 2005 to Neptune Petroleum (Namibia), a wholly owned subsidiary of Tower Resources plc. Arcadia farmed in with an 85% working interest, with Tower Resources plc (through Neptune) owning the balance. Tower has a free carry through the first exploration well and contingent second well.

The Licence is currently in its First Renewal Exploration Period of two years. There are no outstanding obligations for the current period.

The Second Renewal Exploration Period will have a duration of two years until 22nd August 2013 and the minimum work obligation for that Period will be one exploration well and, if necessary, additional seismic acquisition, processing and interpretation, with a minimum expenditure of $10m or $11m respectively. The Licencees have applied for the Second Renewal Exploration Period, and formal agreement was received from the Minister of Mines and Energy on 28th June 2011.

The Licencees plan to drill an exploration well over the Delta structure in Q1-Q2 2012. The 3D seismic survey has assisted in defining the location of the well. If this were a potentially commercial discovery, the Licencees would also consider drilling a second exploration well in 2012 and if successful five wells in 2013 and possibly eight in 2014, with development beginning in 2015 for first production in 2020. The Operator estimates the wells could cost $30m-$35m with mob/demob of $10m for each campaign; this is consistent with current drilling spread rates.

In the event of a commercial discovery, the Licencees may apply for a Production Licence of maximum duration 25 years.

Gross Prospective Resources and Net Attributable to Tower (15% working interest and net of 5% government royalty) are presented for the volatile oil, gas condensate and dry gas scenarios in Table 0.2, Table 0.3 and Table 0.4 respectively.

Risked Prospective Resources attributable to Tower (net of 5% government royalty – Table 0.5) and expected monetary value attributable to Tower (Table 0.6) were calculated by application of an Economic Chance of Success (“ECOS”) of each prospect and lead where:

Economic chance of success = Geological Chance of Success x Economic Probability.

The 3D seismic survey has identified very strong direct hydrocarbon indicators in the Delta Maastrichtian prospect, and clearly detectable but much weaker direct hydrocarbon indicators in the Delta Palaeocene prospect. These greatly increase the geological chances of success ("GCOS") of these two prospects derived from the use only of classical geological component risking. The components of the calculation for each prospect and lead are presented in Table 0.7. The Economic Probabilities that OIL has assigned to each prospect and lead were estimated by applying a blanket Economic Probability of 90% to reflect exogenous economic risks, and potentially reducing this further with reference to the IRR of each development scenario under a stress test of 70% commodity prices plus 130% capital and operating costs.

It should be noted that the results of the 2012 exploration well to investigate the Delta structures will have a material impact on the assessment of contingent and prospective recoverable resources and the geological and economic chances of success of all of the Prospective Resources in the Licence.

Please refer to Sections 1 to 4 and the Appendix of this report for our technical and economic assessment.

The reported hydrocarbon volumes and values are estimates based on professional judgement and are subject to future revisions, upward or downward, as additional information becomes available. The NPVs and EMVs presented in this CPR do not represent OIL's opinion of the open market value of Tower's Namibian Petroleum Assets. OIL does not confirm Tower's legal right to title of its 15% attributable interest in Licence 0010; the detail or the enforceability of its original farm-out agreement with Arcadia; and the absence or nature of any liens or other encumbrances that might affect Tower's rights to, or value in, Licence 0010.

Table 0.1 Summary Licence Information for Licence 0010 Namibia

Date of Namibia Licence 0010	23rd August 2005	Signed by Neptune Petroleum (Namibia) Ltd, a wholly owned subsidiary of Tower Resources plc.
Offshore Blocks covered by Licence	1910A, 1911, 2011A	
Area	23277 km2	
Initial Term	4 years	Expired 23rd August 2009. The Work Obligations were fulfilled and the First Renewal Exploration Period commenced.
Date of First Renewal Exploration Period.	23rd August 2009	Work Obligations: a 1583 km2 3D seismic survey over Delta Prospect commenced on 1st July 2010 and its processing and interpretation were completed in May 2011, fulfilling the work obligation for the First Renewal Exploration Period. Relinquishment: 50% of the licence area; this occurred in August 2009.
Term	2 years	Expires 23rd August 2011
Date of Second Renewal Exploration Period	23rd August 2011	Work and Other Obligations: Exploration well (scheduled for Q1-Q2 2012 on Delta prospect); additional seismic if required.
Term	2 years	The Licencees have applied for the Second Renewal Exploration Period and received formal approval from the Minister of Mines and Energy on 28th June 2011. The Period will expire on 23rd August 2013.
Date of Third Renewal Period	23rd August 2013	Work obligation one well. Relinquishment: a further 25% of the acreage on renewal in August 2013 unless there has been an application for a production licence.
Term	2 years	Expires 23rd August 2015
		A maximum 2-year appraisal programme is permitted following a discovery.
Licencees		
Arcadia Expro Namibia (PTY) Limited (Operator)	85%	Arcadia farmed into Licence 0010 in September 2007.
Tower Resources plc (through Neptune Petroleum (Namibia) Ltd)	15%	Tower has a free carry through two exploration wells (the second contingent).

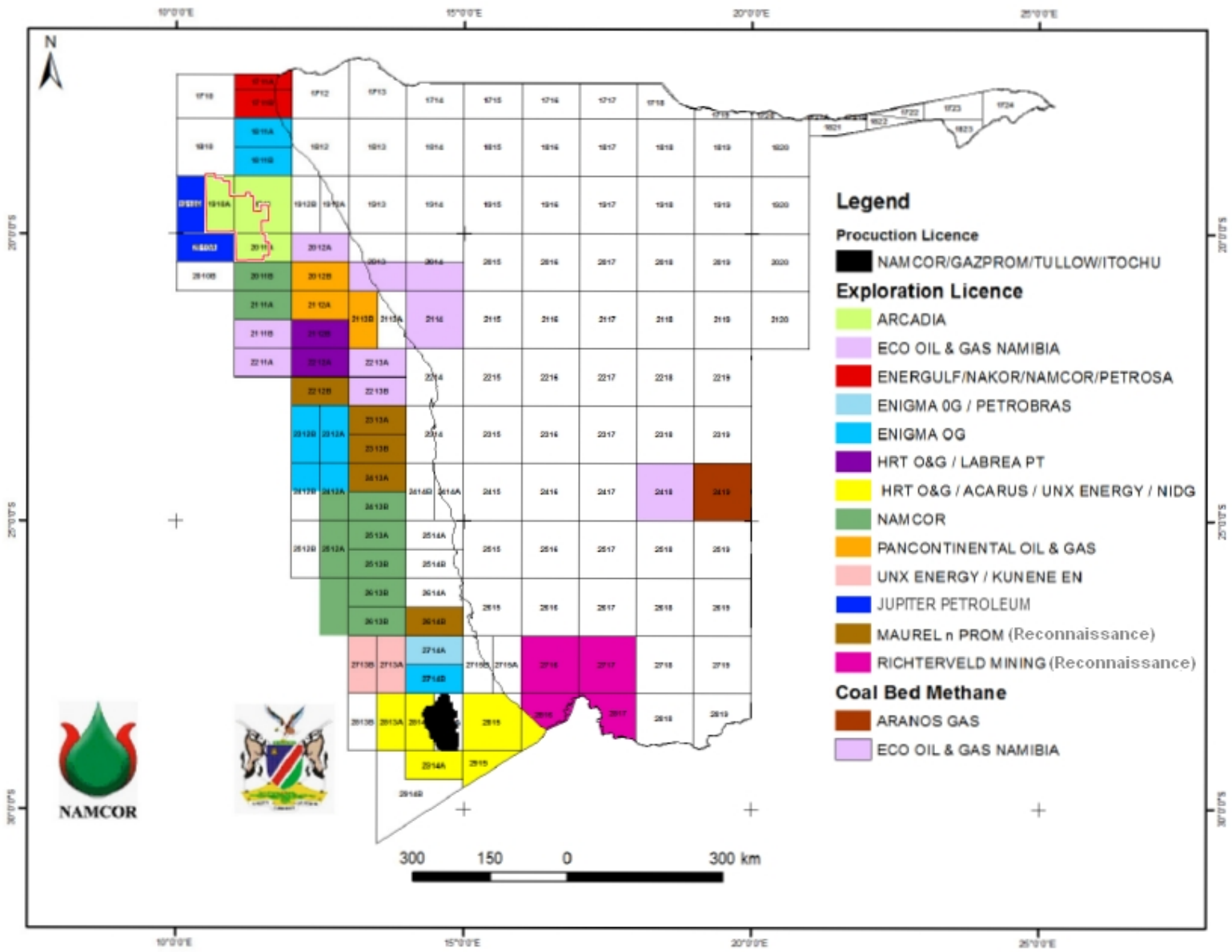

Figure 0.1
Location of
Licence 0010
Namibia

Table 0.2 Gross Prospective Resources and Net Attributable to Tower – Volatile Oil Scenario

Volatile Oil Scenario	**Gross**			**Net Attributable**			**Economic Chance of Success**
	Low Estimate	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**	
Oil and Liquids Prospective Resources	MM STB	MM STB	MM STB	MM STB	MM STB	MM STB	%
Prospects							
Delta Maastrichtian	969.7	2225.8	4010.1	138.2	317.2	571.4	31.4%
Delta Palaeocene	1162.1	3466.1	8091.0	165.6	493.9	1153.0	18.7%
Leads							
Delta Upper Campanian	162.6	438.4	889.6	23.2	62.5	126.8	8.7%
Delta Campanian Wedge	452.3	1146.8	2302.7	64.5	163.4	328.1	9.3%
Delta Albian	507.7	1979.2	4638.2	72.3	282.0	660.9	8.0%
Gamma Palaeocene	831.9	2279.5	5109.8	118.5	324.8	728.1	9.3%
Alpha Palaeocene	326.4	747.8	1515.4	46.5	106.6	216.0	11.8%
Total for Oil and Liquids	**N/A**	**12283.5**	**N/A**	**N/A**	**1750.4**	**N/A**	
Gas Prospective Resources	BCF	BCF	BCF	BCF	BCF	BCF	%
Prospects							
Delta Maastrichtian	1490	3390	6040	213	484	861	31.4%
Delta Palaeocene	1740	5120	11900	248	729	1700	18.7%
Leads							
Delta Upper Campanian	251	674	1370	36	96	195	8.7%
Delta Campanian Wedge	690	1760	3550	98	251	506	9.3%
Delta Albian	954	3560	8660	136	507	1230	8.0%
Gamma Palaeocene	1270	3510	7800	182	500	1110	9.3%
Alpha Palaeocene	494	1150	2320	70	163	331	11.8%
Total for Gas	**N/A**	**19164**	**N/A**	**N/A**	**2730**	**N/A**	

Table 0.3 Gross Prospective Resources and Net Attributable to Tower – Gas Condensate Scenario

Gas Condensate Scenario	**Gross**			**Net Attributable**			**Economic Chance of Success**
	Low Estimate	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**	
Oil and Liquids Prospective Resources	MM STB	MM STB	MM STB	MM STB	MM STB	MM STB	%
Prospects							
Delta Maastrichtian	106.7	267.1	473.6	15.2	38.1	67.5	31.4%
Delta Palaeocene	83.7	248.8	569.6	11.9	35.5	81.2	18.7%
Leads							
Delta Upper Campanian	21.0	56.6	123.5	3.0	8.1	17.6	8.7%
Delta Campanian Wedge	57.9	149.9	324.4	8.3	21.4	46.2	9.3%
Delta Albian	128.9	504.4	1134.5	18.4	71.9	161.7	8.0%
Gamma Palaeocene	81.7	231.8	495.3	11.6	33.0	70.6	9.3%
Alpha Palaeocene	33.4	74.4	153.7	4.8	10.6	21.9	11.8%
Total for Oil and Liquids	**N/A**	**1533.0**	**N/A**	**N/A**	**218.5**	**N/A**	
Gas Prospective Resources	BCF	BCF	BCF	BCF	BCF	BCF	%
Prospects							
Delta Maastrichtian	3360	8080	13600	479	1150	1940	31.4%
Delta Palaeocene	4070	11900	26400	580	1690	3760	18.7%
Leads							
Delta Upper Campanian	573	1510	3210	82	216	458	8.7%
Delta Campanian Wedge	1580	4090	8440	225	583	1200	9.3%
Delta Albian	2050	7970	17900	291	1140	2550	8.0%
Gamma Palaeocene	3060	8590	18400	436	1220	2620	9.3%
Alpha Palaeocene	1240	2810	5710	177	400	813	11.8%
Total for Gas	**N/A**	**44950**	**N/A**	**N/A**	**6399**	**N/A**	

Table 0.4 Gross Prospective Resources and Net Attributable to Tower – Dry Gas Scenario

Dry Gas Scenario	**Gross**			**Net Attributable**			**Economic Chance of Success**
	Low Estimate	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**	
Oil and Liquids Prospective Resources	MM STB	MM STB	MM STB	MM STB	MM STB	MM STB	%
Prospects							
Delta Maastrichtian	8.2	19.4	33.4	1.2	2.8	4.8	31.4%
Delta Palaeocene	9.7	28.1	63.4	1.4	4.0	9.0	18.7%
Leads							
Delta Upper Campanian	1.4	3.8	7.8	0.2	0.5	1.1	8.7%
Delta Campanian Wedge	3.8	9.9	20.6	0.5	1.4	2.9	9.3%
Delta Albian	5.4	20.4	46.8	0.8	2.9	6.7	8.0%
Gamma Palaeocene	6.7	18.9	41.3	1.0	2.7	5.9	9.3%
Alpha Palaeocene	2.7	6.2	12.9	0.4	0.9	1.8	11.8%
Total for Oil and Liquids	**N/A**	**106.6**	**N/A**	**N/A**	**15.2**	**N/A**	
Gas Prospective Resources	BCF	BCF	BCF	BCF	BCF	BCF	%
Prospects							
Delta Maastrichtian	3480	8210	13900	496	1170	1980	31.4%
Delta Palaeocene	4060	11900	26400	579	1690	3760	18.7%
Leads							
Delta Upper Campanian	583	1600	3250	83	229	463	8.7%
Delta Campanian Wedge	1610	4180	8620	229	595	1230	9.3%
Delta Albian	2260	8640	19500	322	1230	2780	8.0%
Gamma Palaeocene	2830	8000	17200	404	1140	2450	9.3%
Alpha Palaeocene	1120	2630	5430	160	374	774	11.8%
Total for Gas	**N/A**	**45160**	**N/A**	**N/A**	**6428**	**N/A**	

Table 0.5 Risked Prospective Resources Attributable to Tower

	Net Attributable Best Estimate			Fluid Probabilities			Fluid Probabilities x Net Attributable Best Estimate			Aggregate Fluid-Weighted Net-Attrbutable Best Estimate	Economic Chance of Success	Net Attributable Risked Prospective Resources
	VO	GC	DG	VO	GC	DG	VO	GC	DG			
Oil and Liquids Prospective Resources	MM STB	MM STB	MM STB	%	%	%	MM STB	MM STB	MM STB	MM STB	%	MM STB
Prospects												
Delta Maastrichtian	317.2	38.1	2.8	50%	40%	10%	158.6	15.2	0.3	174.1	31.4%	54.7
Delta Palaeocene	493.9	35.5	4.0	50%	40%	10%	247.0	14.2	0.4	261.5	18.7%	48.9
Leads												
Delta Upper Campanian	62.5	8.1	0.5	50%	40%	10%	31.2	3.2	0.1	34.5	8.7%	3.0
Delta Campanian Wedge	163.4	21.4	1.4	50%	40%	10%	81.7	8.5	0.1	90.4	9.3%	8.4
Delta Albian	282.0	71.9	2.9	50%	40%	10%	141.0	28.8	0.3	170.1	8.0%	13.6
Gamma Palaeocene	324.8	33.0	2.7	45%	44%	11%	146.2	14.5	0.3	161.0	9.3%	15.0
Alpha Palaeocene	106.6	10.6	0.9	45%	44%	11%	48.0	4.7	0.1	52.7	11.8%	6.2
Total for Oil and Liquids	**1750.4**	**218.5**	**15.2**							**944.3**		**149.8**
Gas Prospective Resources	BCF	BCF	BCF	%	%	%	BCF	BCF	BCF	BCF	%	BCF
Prospects	VO	GC	DG	VO	GC	DG	VO	GC	DG			
Delta Maastrichtian	484	1150	1170	50%	40%	10%	242	460	117	819	31.4%	257
Delta Palaeocene	729	1690	1690	50%	40%	10%	365	676	169	1210	18.7%	226
Leads												
Delta Upper Campanian	96	216	229	50%	40%	10%	48	86	23	157	8.7%	14
Delta Campanian Wedge	251	583	595	50%	40%	10%	126	233	60	418	9.3%	39
Delta Albian	507	1140	1230	50%	40%	10%	254	456	123	833	8.0%	67
Gamma Palaeocene	500	1220	1140	45%	44%	11%	225	537	125	887	9.3%	83
Alpha Palaeocene	163	400	374	45%	44%	11%	73	176	41	290	11.8%	34
Total for Gas	**2730**	**6399**	**6428**							**4614**		**719**
												MM Boe
Total for Gas (MM boe)	**(If we assume 1 boe = 6000 SCF)**											**119.9**
Net Attributable Risked Prospective Oil and Gas Resources (MM boe)												**269.7**

Key: GC = Gas Condensate Scenario; VO = Volatile Oil Scenario; DG = Dry Gas Scenario.

Table 0.6 Expected Monetary Value Attributable to Tower

Prospective Resource	Working Interest	Net Attributable NPV 10%	Net Attributable Cost of Failure	Economic Chance of Success	Net Attributable EMV 10%
	%	$ million	$ million	%	$ million
Prospect					
Delta Maastrichtian	15%	$2,393	$10	31.4%	$744
Delta Palaeocene	15%	$4,196	$10	18.7%	$776
Leads					
Delta Upper Campanian	15%	$451	$10	8.7%	$30
Delta Campanian Wedge	15%	$1,363	$10	9.3%	$118
Delta Albian	15%	$2,595	$10	8.0%	$198
Gamma Palaeocene	15%	$2,560	$21	9.3%	$219
Alpha Palaeocene	15%	$743	$21	11.8%	$69

Table 0.7 Calculation of GCOS and ECOS for the Prospects and Leads

Component Probability	Delta Maastrichtian	Delta Palaeocene	Delta Upper Campanian	Delta Campanian Wedge	Delta Albian	Alpha Palaeocene	Gamma Palaeocene
I-GCOS	**23.0%**	**18.4%**	**13.0%**	**13.0%**	**10.6%**	**16.7%**	**9.7%**
AVO Multiplier	172%	129%	115%	100%	100%	122%	122%
TOTAL GCOS	**39.5%**	**23.6%**	**14.9%**	**13.0%**	**10.6%**	**20.4%**	**11.9%**
Economic Probability	79%	79%	58%	72%	76%	58%	78%
TOTAL ECOS	**31.4%**	**18.7%**	**8.7%**	**9.3%**	**8.0%**	**11.8%**	**9.3%**

Qualifications

OIL is a privately owned energy consultancy founded in 1990 that has advised on oil and gas projects in over 40 countries. OIL's shareholders, management and staff are, and always have been, independent of shareholders, management and staff of Neptune Petroleum (Namibia) Ltd, Arcadia Expro Namibia (PTY) Limited, Arcadia Petroleum Ltd and Tower Resources Plc.

This CPR was produced by four consultants: Mr David Curia, Mr Victor Ploszkiewicz, Mr Stephen Foster and Mr Tim Lines. All hold degrees in geoscience or petroleum engineering. Messrs Curia and Ploszkiewicz (both based in Buenos Aires) have extensive exploration experience on both sides of the South Atlantic rift.

Mr David Curia has 28 years' experience in geophysical interpretation and 3D modelling. He holds a M.Sc. in Geology, a M.Sc. in Mathematics from the University of Buenos Aires, and a "Post-Degree" in Geophysics (12 geophysical subjects examined over 18 months, without a doctoral thesis) from the University of Mendoza. He has held lectureships in Numerical Analysis and in Geostatistics. He is the author of over 20 papers for a.o. the European Association of Geoscientists and Engineers and the American Association of Petroleum Geologists.

Mr Victor Ploszkiewicz has 36 years' experience in geological interpretation and holds a M.Sc. in geology from the University of Buenos Aires. He was visiting professor in geology at the University of Mendoza. He is author of over ten research papers for a.o. the Society of Exploration Geophysics and the American Association of Petroleum Geologists. He is a Member of: The American Association of Petroleum Geologists (M.AAPG); The Society of Exploration Geophysicists (M.SEG); The Asociacion Argentina de Geologos y Geofisicos Petroleros (M.AAGyGP); and The Asociacion Geologica Argentina (M.AGA).

Mr Stephen Foster has 36 years' experience as a geophysicist and holds a B.S. in Geology from the University of California and an M.S. in Earth Science from Massachusetts Institute of Technology. He is Registered Geophysicist No. 910 (California). He has practical experience in seismic data acquisition.

Mr Tim Lines has 29 years' experience in petroleum engineering and economic evaluation. He holds a B.Sc. in Chemistry from Bristol University, a M.Sc. in Petroleum Engineering from Imperial College and an MBA from Cranfield University. He is a Chartered Engineer registered with the UK Engineering Council since 1990 and has been Vice Chairman of the Society of Petroleum Engineers London since 2000. He is a member of the Institution of Gas Engineers (M.IGEM) and the Energy Institute (M.EI), the Institute of Materials, Minerals and Mining UK, and the Geological Society of London. He has the Freedom of the City of London as a Liveryman of the Worshipful Company of Fuellers.

Basis of Opinion

This CPR is based on OIL's understanding of the current petroleum legislation, taxation and other regulations pertaining to Namibia. It is also based on a forecast from 2020 to 2040 of oil prices in USA and gas prices in Western Europe. It is emphasised that legislation, taxation and commodity-price forecasts can be subject to significant change even in the short term and that any of these could have a significant effect on the NPVs and EMVs presented in this CPR.

Yours sincerely

Tim Lines
Director, Oilfield International

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1 The Geology of Namibian Licence 0010

1.1 Regional Perspective

A summary of the regional setting and petroleum system in the Namibe and Walvis Basins is presented below, to assist in understanding (a) the Licence-specific work which is the subject of this report and (b) how the extensive regional work by many parties has influenced the Prospective Resource risk assessments, particularly with respect to reservoir, hydrocarbon type, charge and geological chance of success.

The SW Africa offshore margin is composed by four passive marginal basins called, from north to south: Namibe, Walvis, Lüderitz and Orange In this context the Phanerozoic tectonic extensional activity is very well manifested in these marginal basins through a number of unconformities along the depositional sequences.

Both the Namibe and Walvis Basins are marked by Palaeozoic to Cenozoic sedimentation formed essentially by Syn-Rift (Permian to Early Triassic), Early Drift (Aptian to Cenomanian) and Late Drift (Turonian to Recent) Sequences. The Namibe and Walvis Basin are a typical post-rift wedge shaped basins, with the geometry of a passive margin and water depths of 150–3000 m, which is an appealing basin for exploration of hydrocarbons and several drilling results prove elements of a viable petroleum system. However, these are sparsely explored areas - to date nine exploration wells have been drilled offshore Namibia.

The Namibian margin south of the Walvis Ridge is proven to host productive rift system source rocks as well as Lower Aptian marine oil prone facies and Cenomanian – Turonian source rocks. Gas is the dominant phase found to date and this appears to be a function of high maturity in Block 2814 the area of the main discovery (Kudu – 900 km to the south east) which lies below the very thick Orange delta sediment deposits. Despite this, source rock characteristics are oil prone and oil is the expected phase in most of the prospectivity identified in Chariot's exploration areas to the north east (refer Figure 0.1)

Not far from the reference blocks, Chariot undertook an extensive seismic acquisition programme across the Northern blocks 1811A/B focusing on an area of specific interest over the previously identified Zamba prospect. As well as the Zamba prospect, another four stacked leads have been identified in the Tapir Complex. This area has proven hydrocarbon potential as evidenced by the Kunene-1 well in Block 1711 250 kms to the north which shows potential for up to 14 TCF of gas (as reported by the Namibian Ministry of Mines and Energy). Chariot claims that basin modelling based partly on the analysis of wells on Licence 0010 demonstrates the potential for oil in 1811A/B. (Our own analysis of Licence 0010 to the south suggest the (marginally) most likely fluid scenario is a Volatile Oil).

The presence of numerous "slicks" from oil seepages in a.o. the Chariot blocks confirm the geochemical modelling.

The 1.3 TCF Kudu field (upside 9 TCF) was scheduled to achieve first gas in 2014 from a $1bn 800 MW gas-to-power development however Gazprom, a key partner, pulled out in May 2011 reportedly over a disagreement on the price offered by South Africa for surplus gas.

1.2 Brazil and the South Atlantic

Brazil and Namibia shared similar geology before the South Atlantic break-out and pull-apart (Figure 1.2 refers). The Namibia offshore basins (Walvis, Luderitz and Orange) mirror the Santos and Campos basins in Brazil, which are highly prospective. The Upper Aptian-Barremian is an important source rock for Brazil's offshore oil fields and the likelihood that analogous petroleum systems are present is increased by the condensate samples from the Kudu field showing similar "fingerprints" to the Brazilian source rocks. The presence of an active oil system in the recent discoveries in the Falklands basin supports South-Atlantic prospectivity.

An analysis of the Campos and Santos basins is therefore relevant to Namibian prospectivity. Table 1.1 presents an analysis by IHS[1] of the ANP (National Hydrocarbon Agency of Brazil) exploration statistics from 2006-2007 for drilling activity offshore Brazil. The ANP requires operators to file "hydrocarbon show" reports within 72 hours of an operator verifying them by two different independent methods. The filings therefore indicate when hydrocarbons were encountered in exploration wells, although this does not necessarily imply a commercial discovery. IHS recategorised the data to show suspended oil and gas wells, which is probably a better guide to potentially commercial discoveries. The Brazilian experience is clearly encouraging.

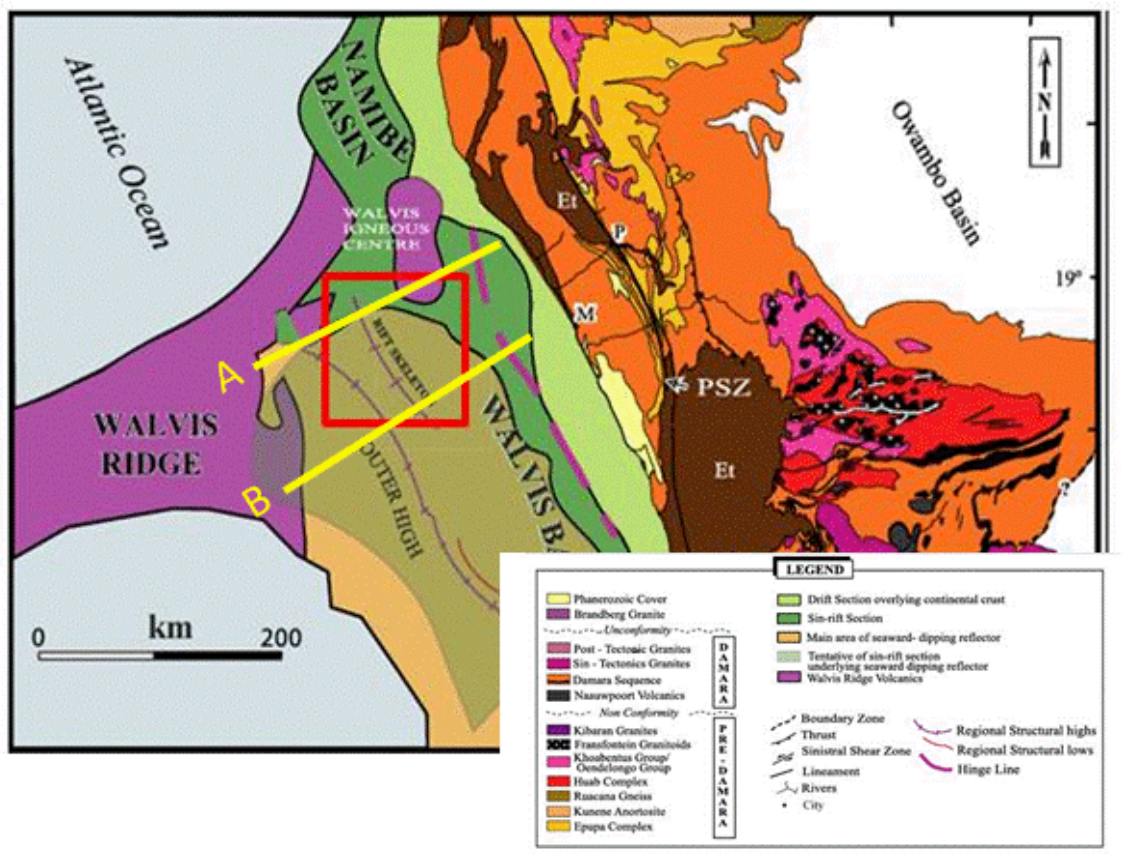

Figure 1.1 Licence 0010 in the geological context

In conclusion the high exploration success rates encountered in similar basins in Brazil is of significant relevance to the prospectivity of Namibia.

[1] Annual Synopsis, Brazil 2007, 2006, IHS

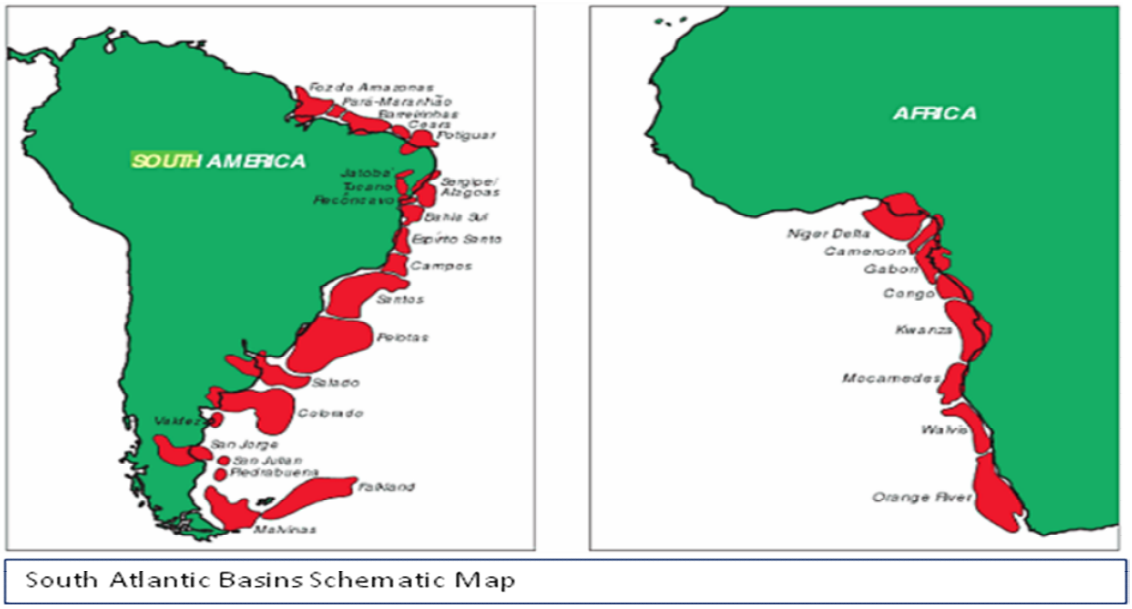

Figure 1.2 Basin-mirroring in the South Atlantic

Table 1.1 Brazil exploration well success rates

	No. of Exploration Wells	Suspended Oil and Gas Wells	Dry & Non Commercial	% Success
2007				
Offshore	49	32	17	65%
Onshore	108	56	52	52%
Total	157	88	69	56%
2006				
Offshore	53	24	29	45%
Onshore	58	13	45	22%
Total	109	37	74	34%

1.3 Seismic Data on Licence 0010

The 2010 3D seismic survey acquired over the Delta structure is of very good quality and clearly delineates five potentially very large reservoirs The 2D seismic coverage (various vintages) also clearly delineates one even larger structure (Gamma) and one smaller one (Alpha). Figure 1.3 and Figure 1.4 refer.

We have used the seismic data to calculate the areas and gross rock volumes of these potential reservoirs and these data are summarised in Table 3.3 and Table 3.4.

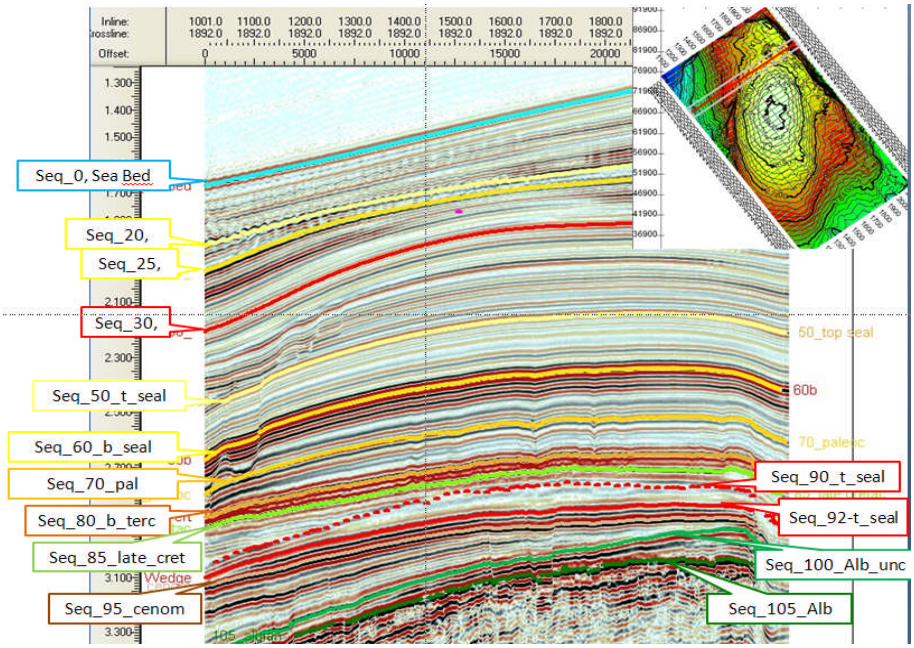

Figure 1.3 Selected 3D crossline over Delta, showing the seismic markers and unconformities

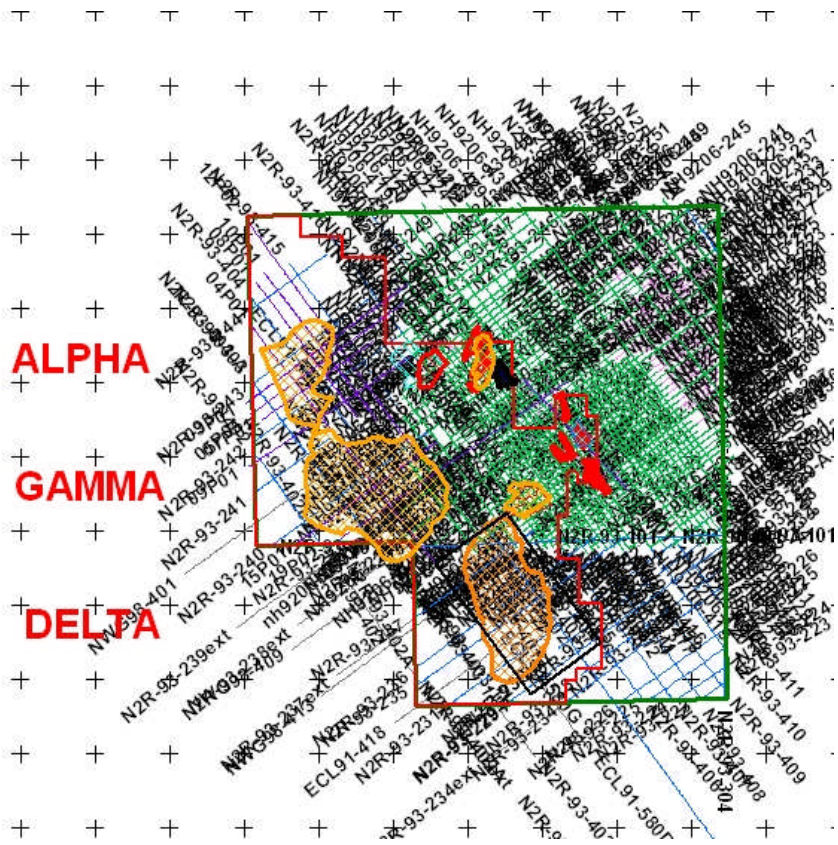

Figure 1.4 Relinquishment and Main Structures

1.4 Source rocks

The area has been the subject of several geochemical studies and source-rock maturity models. In general these studies focused on the source potential of shale sections penetrated by the two wells drilled in the Block about 60 kms northeast of Delta. Additional supplementary maturity models were based on the drilled wells and two synthetic wells, one in the deeper part region of the north and other in the depocenter at the central part of the Block. The structural maps representing the tops of those units containing source rocks were also considered.

The two wells penetrated three potential source rocks: the Uppermost Cenomanian, the Mid Albian-Upper Aptian and the Upper Aptian-Barremian. In 2006, Tower engaged SPT-Robertson Research to undertake a geochemical evaluation of Well 1911/15. Two potential source rocks were identified, one in the Santonian at 3215 - 3365 m, the other in the Turonian – Cenomanian at 3455 - 3478 m depth.

The study was mainly focused on the Dolphin graben, nevertheless it did identify a small area located northwest of block, where the Cenomanian-Turonian may be below 4600 m depth; i.e. in the gas window thus providing a source for gas condensate. Figure 1.5 refers, showing a small area near the north limit (red) where Cenomanian and Turonian source rocks are in gas window. Green areas represent the Cenomanian-Turonian in the Oil Window. A subsequent 2007 seismic survey also shows an abrupt deepening to the north and west of the structural trend of Alpha, Gamma and Delta which should continue to deepen towards the Atlantic basin, providing further sources of gas/gas condensate. It is clear that much of the Turonian-Cenomanian near the Licence 0010 structures is in the oil window.

The report also identified the Upper Aptian-Barremian and the Jurassic sediments as mature by the Eocene and this is particularly sigificant in view of the presence of chimneys rooted below the Albian in the Delta structure.

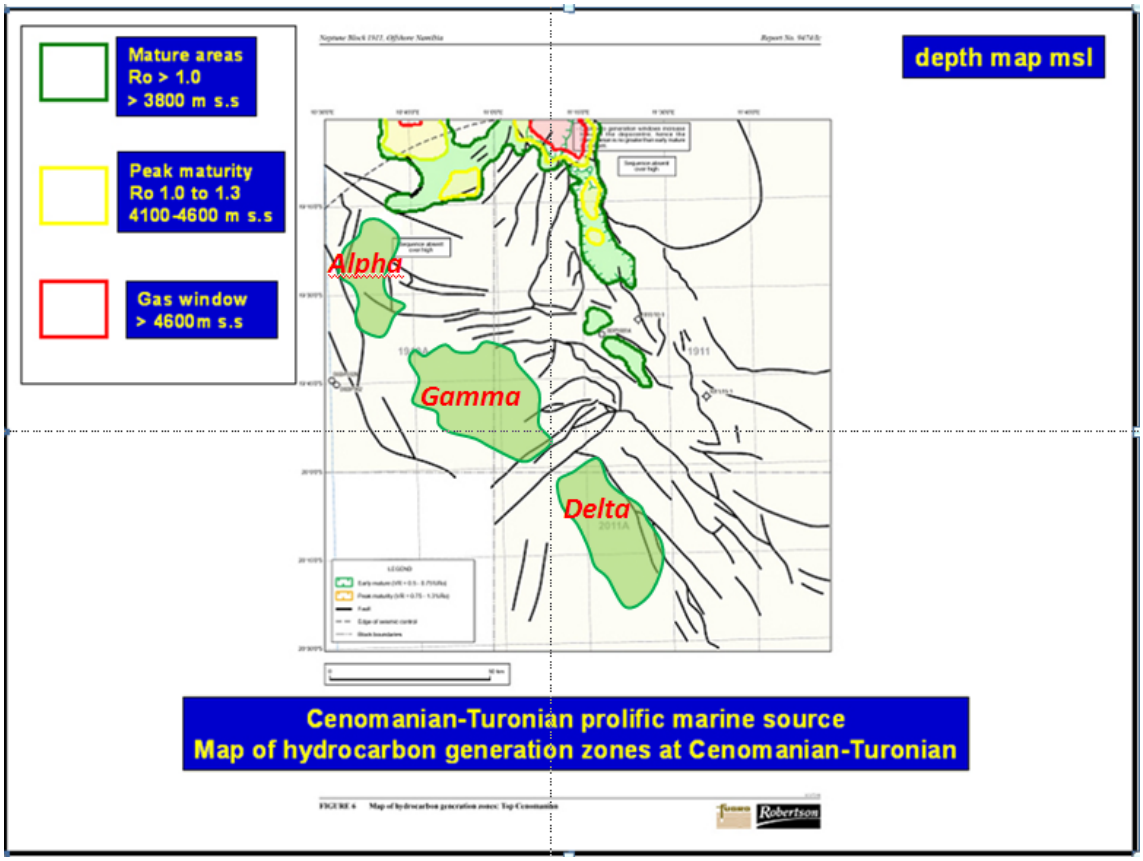

Figure 1.5 Potential Source Rocks for Licence 0010. (From RRI 2006 report) and approximate location of Alpha, Gamma and Delta structures

2 Possible fluid-types in the Prospective Resources

The Prospective Resources could contain dry gas; gas condensate; volatile oil with or without a gas cap; or black oil with a gas cap. In this section we assess the evidence for each and present a table of probabilities for each fluid-type.

2.1 AVO and Gas vs. Light Oil

In our view AVO anomalies are of primary use in detecting the presence of light hydrocarbons. This is because the anomaly is a response to a drop in the *VP/VS* ratio across the interface from the seal to the reservoir. And although much emphasis is placed on the importance of *VS*, it is the *VP* that responds to the gas. Indeed it is the fact that *VP* is highly sensitive to gas and *VS* is insensitive to gas that allows classical AVO analysis to identify hydrocarbons. In other words, if a trap were filled only with heavy oil (single phase), there would not be an AVO anomaly.

However, light oil at Delta horizon depths will, under favourable conditions, produce an AVO anomaly[2]. Even if conditions were not conducive, there is good evidence (see below) for oil generation.

2.2 Shows in the Well 1911-15

Although no oil shows or oil-cut (carbon-tetrachloride-solvent-extracted) were observed while drilling, some pale fluorescence was seen in the drill cuttings.

However the more intriguing and encouraging data are from one Albian carbonate core (3650-3750m) where gas chromatograms from core-extracts demonstrated lighter-ends. They also showed "low isoprenoid /n-alkane ratios and C-preference indices near 1.0. We believe these are evidence, among other indicators, that a mature source rock yielded these traces of residual oil. Holtar and Forsberg (2000) concluded that these hydrocarbons may have migrated from a mature source kitchen, either in a liquid phase as light oil or in a gaseous phase as a condensate. The authors were not able to be precise about the location of the source, however.

2.3 Oil seeps/slicks

The NPA report discusses a number of oil slicks in the east of the 0010 Licence, which they categorise as evidence that either oil was generated near the Namibian coast, or oil-spills from passing vessels, or seeps from a trap alongside gas bubbles. They note that the slicks are not over any closures. In our view the report is a useful indicator.

2.4 Adjacent Block Interpretations

Namcor have interpreted an adjacent area to Delta as an oil-prone structure (they do not cite a gas case). Since we and they presumably are using the same data and maturity models, it would be useful to know if they are referring to a structure or a trap with AVO-anomalies, and if so, how they have reached their (gas-free) conclusions. However, in the absence of more information, we feel we can do no more than simply note their report. We have also studied Chariot's 6/2011 presentation on Blocks 1811, 2312 and 2714 and 9/10 CPR – noting the Tapir lead where AVO anomalies were identified in Palaeocene rocks; Energulf's 2/2011 update on Block 1711 (Kunene) and 5/2010 presentation on Blocks 1711 , 2713 and 2815;and UNX (now HRT SA) D&M resource reports on 2713, 2813, 2815.

2.5 Basins have generated both oil and gas

The basins have generated both oil & gas (refer NPA 2010), as demonstrated in fields and discoveries in the Orange and Namibe basins.

[2] OIL has conducted acoustic impedance calculations after Gassman and Batzle-Wang to demonstrate this.

2.6 Cenomanian-Turonian Maturity

Figure 1.5 above refers. It is clear that this is a potentially important source rock for gas, gas condensate and oil.

2.7 The Kunene gas field

We use this as an analogue for the dry gas scenario despite it being located 250 km to the north (ref) because it is the only and closest drilled prospect in the Namibe Basin. Incidentally the pre-drill prognosis for Kunene was made considering an oil case and gas case (refer Netherland and Sewell; Energulf, E&P News 21/3/2007).

2.8 Probabilities of the Different Fluid Types

Both the Structures and the Inter-structural Areas are located at a relatively high point regionally. This favours migration of hydrocarbons to this area from the Cenomanian-Turonian hydrocarbon-source-rock, underlying the Campanian, Maastrichtian and Palaeocene Delta sediments. Furthermore the Cenomanian-Turonian source-rock is generally shallower than it is in the Kunene area to the north-east and this increases the probability that it would have generated heavier hydrocarbons (i.e. volatile oil or wet gas) in Licence 0010 rather than the dry gas observed in Kunene (refer Section 2.7).

In summary, based on the above discussion we would expect:

a. The probability of hydrocarbons being in the gaseous and liquid phases to be similar; i.e. 50/50.

b. If the phase were gas, we believe it is much more likely to be gas condensate than dry gas, because the depth of burial of the source rocks in this area is not deep enough for dry gas.

On the basis of the above comments, the relative probability of the different phases of hydrocarbons in the traps is presented in Table 2.1.

We have no strong views about the relative likelihood of volatile-oil vs. black-oil-with-a-gas-cap (both of which can display AVO-anomalies), and so we have defined a single phase volatile oil. Vapour-Liquid-Equilibrium (VLE) calculations were conducted to estimate the GOR of single-phase oils and dense phase "gases" for the different leads.

Table 2.1 Probability of Fluid Type in Licence 0010

Fluid Type	Delta Prospect and Leads	Alpha, Gamma and Inter-structural Areas
Dry Gas	10%	11%
Gas Condensate	40%	44%
Volatile Oil	50%	45%
Total	100%	100%

3 Prospects and Leads

OIL has identified two Prospects, five Leads and three Plays in Licence 0010. There are no recoverable reserves or contingent resources in Licence 0010. The assets are all Prospective Resources in the Namibe and Walvis Basins.

- There are two Prospects, namely Delta Maastrichtian and Delta Palaeocene. These are the principal targets of the first exploration well.
- There are three Leads in Delta namely: Delta Upper Campanian, Delta Campanian Wedge, Delta Albian. These are secondary targets for the first exploration well.
- There are two further Leads: Alpha Palaeocene and Gamma Palaeocene
- There are three Plays, namely the GE, BA and AG Inter-Structural Areas
- There are other Plays at early stages of evaluation. These could become more significant in the event of success in the first drilling campaign.

This report only considers the Delta prospects and leads in more detail, since the 3D survey greatly increases resolution on this structure. The Alpha and Gamma leads were considered in the 2010 report and only their economics are updated here.

3.1 Estimation of Geological Chance of Success (GCOS)

We made an initial assessment of GCOS from the classical parameters (Structure/Trap; Seal, Reservoir; hydrocarbon charge; and Timing of hydrocarbon migration) using the available geological tools and data. This "Initial GCOS ("I-GCOS") was based on studies of: the depositional environment, Time-structure and Depth-converted maps (supported by seismic data and wells), geochemical studies of rocks, as well as properly balancing available well information.

We then assessed the quality of the AVO-anomalies[3] from the 3D seismic surveys, and we applied an AVO-Multiplier to the I-GCOS to reflect any additional confidence that the AVO-anomalies provide. The AVO-Multiplier was larger, the better the quality of the anomaly[4].

We also use the presence of AVO anomalies to define our P99 and P50 areas where there was no other evidence of a closure inside which the AVO anomalies are located.

The clarity of the 3D seismic shows there is no doubt about the structural integrity of the four-way dip closure of the top four horizons. The Albian is a three-way dip closure controlled by a normal fault in the northeast side and so we have assigned it less confidence. Table 3.1 refers.

The depositional environment and sheer scale of the horizons of the Maastrichtian and Palaeocene prospects implies it is quite reasonable to postulate that the reservoir sands identified in the two wells 60km to the north east persist at Delta for these horizons. The other reservoirs are more speculative.

The the sheer number and longevity of pockmarks (chimneys), some rooted below the Albian, combined with the large volume of nearby oil-prone source rock, and early structural development provides ample confidence for hydrocarbon charge.

The vertical seal seems to be effective, based on the observed AVO effects at the apex of the Maastrichtian anticline; multiple shale layers interbedded with the sandstone beds, the shale content increases upwards (for the Palaeocene); the probable existence of a flooding surface of regional

[3] AVO is an abbreviation for Amplitude Versus Offset, a mathematical process for transforming seismic data into a quantitative rock property description of a reservoir.

[4] This method was developed by the DHI consortium; reference: http://dhi.roseassoc.com/index.html

extension, for example the shale layer at 2620m in well 1911-15 between the Campanian and Maastrichtian horizons (Campanian); and the thick layer of Late Albian and Cenomanian rich organic deep water marine shales (Albian).

Timing is not a material risk, since the maturity models indicate that the source rock is still in the oil/gas window.

The AVO-anomalies over the Delta Maastrichtian structure are of very good quality. They are extensive and fully coherent with the structure with no anomalies off structure. The presence of extensive chimneys adds further weight Hence we have calculated an AVO multiplier of 1.72. This increases the Initial GCOS (based on geological parameters) from 23% to 39.5% GCOS, which is very high for an exploration well in a poorly explored basin. However, the direct hydrocarbon indicators are very strong indeed, and as the IHS analysis demonstrates (Table 1.1), the mirror basins in Brazil have very high success rates for exploration wells.

There is a detectable but much weaker AVO response in the Delta Palaeocene structure compared with the Maastrichtian, and some of the anomalies are also not coincident with the structure. Our assessment of the full range of attributes similarly identifies inconclusive but by no means insignificant evidence of direct hydrocarbon indicators. The semi-quantitative scoring method results in a calculated AVO Multiplier of 129%, and this is consistent with our more qualitative view.

Although there are AVO anomalies in the Upper Campanian, they are weak and mainly outside of the structure. The low AVO-Multiplier reflects this.

There are no AVO anomalies in the Campanian Wedge or the Albian, and so no multiplier was included. The absence of AVO anomalies does not imply the absence of hydrocarbons; for example the lead could be filled with black oil with no gas cap. (High quality AVO anomalies at these depths do not differentiate between gas, gas condensate, very light oil, or black oil with a gas cap).

Table 3.1 Components of GCOS and ECOS calculation for each prospect and lead

Component Probability	Delta Maastrichtian	Delta Palaeocene	Delta Upper Campanian	Delta Campanian Wedge	Delta Albian	Alpha Palaeocene	Gamma Palaeocene
Structure	100%	100%	100%	100%	70%	90%	90%
Reservoir	50%	40%	30%	30%	30%	50%	40%
HC Charge	60%	60%	60%	60%	70%	55%	40%
Seal	85%	85%	80%	80%	80%	75%	75%
Timing	90%	90%	90%	90%	90%	90%	90%
I-GCOS	**23.0%**	**18.4%**	**13.0%**	**13.0%**	**10.6%**	**16.7%**	**9.7%**
AVO Multiplier	172%	129%	115%	100%	100%	122%	122%
TOTAL GCOS	**39.5%**	**23.6%**	**14.9%**	**13.0%**	**10.6%**	**20.4%**	**11.9%**
Economic Probability	79%	79%	58%	72%	76%	58%	78%
TOTAL ECOS	**31.4%**	**18.7%**	**8.7%**	**9.3%**	**8.0%**	**11.8%**	**9.3%**

3.2 Recovery Factors

No data on recovery factors for the area were available and so some typical industry norms were assumed.

3.2.1 Dry Gas

There are no regional data, so a range of 60%-80% was selected as typical for gas reservoirs. The condensate recovery factor is assumed to be the same.

3.2.2 Gas Condensate

The gas recovery factor would be less for a gas condensate than for a dry gas because liquids condense in the reservoir, restricting flow paths. Condensate recovery factors would typically be less still. Table 3.2 presents the assumptions that we have used, based on a survey of SPE papers on this subject[5].

Table 3.2 Gas and Gas-Condensate Recovery Factors assumed in the resource calculations

Lead/Horizon	Minimum (P99)	Best Estimate (P50)	Maximum (P1)
	(Fraction)	(Fraction)	(Fraction)
Gas	0.5	0.6	0.7
Condensate	0.3	0.4	0.5

3.2.3 Oil

The oil we have assumed has a high GOR. It would be light and non-viscous with an API gravity of over 40 degrees. Therefore it should achieve quite high recoveries so long as gas breakthrough can be avoided using standard industry practice. We have therefore selected a range of 30%-40% recovery factor for the oil. The solution gas would initially be reinjected for partial pressure support and then produced after perhaps 50% of the oil had been recovered.

3.3 Initial Hydrocarbon Saturations

There are no regional data on initial hydrocarbon saturations so a range of 60%-80% was selected as typical.

3.4 Reservoir Parameters

The P50 reservoir parameters used in the analysis are presented in Table 3.3 and Table 3.4. These were used, alongside P1 and P99 values to calculate resource volumes for the prospects and leads.

[5] SPE 95531, 59772, 120743 and published reports on Karachaganak field, Kazakhstan

Table 3.3 P50 Reservoir parameter for the Monte Carlo resource volume calculations

Reservoir Characteristic	Units	Maastrichtian	Palaeocene	Upper Campanian	Campanian Wedge	Albian
Apex	m subsea	2,110	1,970	2,150	2,230	2,530
Closing Contour	m subsea	2,180	2,020	2,200	2,300	2,600
Vertical Relief	m	70	50	50	70	70
Area of Trap	km2	427	222	220	367	256
Gross Pay	m	65	125	30	70	65
Gross Rock Volume	MM m3	22,500	27,700	6,392	11,920	7,630
Net to Gross	fract	0.50	0.31	0.30	0.45	0.50
Porosity	fract	0.22	0.22	0.18	0.18	0.15
Initial Gas or Oil Saturation	fract	0.70	0.70	0.70	0.70	0.70

Table 3.4 Areas and hydrocarbon water contacts for the resource calculations

Prospective Resource	Low Estimate		Best Estimate		High Estimate	
	HWC	Dimensions	HWC	Dimensions	HWC	Dimensions
Prospects	m subsea	km x km	m subsea	km x km	m subsea	km x km
Delta Maastrichtian	2120	14.4 x 7.3	2180	33.8 x 15.1	2240	56 x 20.8
Delta Palaeocene	1980	6.1 x 2.6	2020	26.3 x 11.6	2120	58.4 x 24.1
Leads						
Delta Upper Campanian	2160	9.1 x 5.2	2200	22.7 x 12.1	2300	49.5 x 20.7
Delta Campanian Wedge	2250	11.2 x 8.5	2300	27.8 x 15.7	2350	38.5 x 20.7
Delta Albian	2540	10.1 x 6.3	2600	22.2 x 9.3	2860	50.2 x 27.1
Alpha Palaeocene	1975	15.0 x 11.4	2050	19.3 x 15.3	2075	35.1 x 18.7
Gamma Palaeocene	1950	11.0 x 8.4	2025	14.9 x 12.1	2075	48.9 x 39.1

4 Economics of Licence 0010

4.1 General

NPVs of estimated after-tax cash flows (as at 31st May 2011) attributable to Tower have been calculated at a nominal discount rate of 10% for the seven prospects and leads. OIL's assessment is based upon commodity pricing and exchange rate assumptions presented in Section 4.4.3,; and OIL's understanding of the fiscal and contractual terms governing the Licence presented in Section 4.4.2. No adjustments have been made for cash balances, inventories, indebtedness or other balance-sheet items.

The reported hydrocarbon volumes and values are estimates based on professional judgement and are subject to future revisions, upward or downward, as additional information becomes available. The NPVs and EMVs presented in this report do not represent OIL's opinion of the open market value of Tower's Namibian Petroleum Assets.

NPVs have been calculated for the seven prospects and leads for the following matrix of nine cases.

Prospective Resources	Gas Condensate	Volatile Oil	Dry Gas
Low Estimate	"GC-Low"	"VO-Low"	"DG-Low"
Best Estimate	"GC-Best"	"VO-Best"	"DG-Best"
High Estimate	"GC-High"	"VO-High"	"DG-High"

4.2 Field Development Plans

4.2.1 Volatile Oil Field Development Plan

The volatile fluid is assumed to be at bubble-point pressure and this implies GORs in the range 1700 – 2500 SCF/STB and Bo: 1.52 – 1.85 (res vol/std vol).

The development strategy that OIL has proposed for the Volatile Oil Scenario is to produce the oil whilst initially reinjecting the gas. This would reduce the pressure decline in the reservoir during oil production and so reduce the evolution of gas in the reservoir. Gas production would commence after six years of injection. The development plan has the benefit of delaying construction of the LNG liquefaction facility and LNG ships by six years, and the 450km gas pipeline to Walvis Bay. This also means that where a Phase 2 field development is required, economies of scale are gained by combining LNG and pipeline capacity.

Water injection would also be required to reduce the pressure decline in the reservoir and to sweep the oil to the production wells, to improve recovery. We assumed a ratio of approximately one water injection well to 2.5 oil production wells, which is within industry norms.

OIL has assumed an average production rate of 10,000 STB/D for each well as a realistic figure upon which to base the NPV calculations. OIL also assumed that approximately 8% of recoverable oil would be produced during each of the six years on plateau (a figure within the typical range for offshore oil developments), and that each well on average would have a maximum ultimate recovery of approximately 27 MMSTB.

The offshore facilities that OIL has defined utilise a standard approach for deepwater developments: wet trees; subsea manifolds and satellite-wells; flexible risers to a dynamically-positioned FPSO with large storage capacity; and a tanker-loading bouy. The FPSO would produce tanker-stabilised oil and reinject gas. After six years it would produce and export low dewpoint gas. The maximum step-out for deviated wells assumed was 3km.

The gas pipeline to Walvis Bay and an onshore LNG facility would be constructed to start operation six years after commencement of oil production. If a development were to justify two phases, the second

would realistically come on stream about five years after the first and so the pipeline and LNG plant would take advantage of economies of scale.

The "Low Estimate" of recoverable resources of the smaller leads clearly do not justify an LNG plant (up to at least 200 MMSCFD). OIL calculated the NPVs of simply giving the gas to the Walvis Bay community: - the NPVs are similar to building an LNG plant (or leaving the gas in the reservoir) because the tax system places most of the cost of the loss-making LNG plant on the Namibian government. This may be a win-win proposal for all parties.

4.2.2 Gas Condensate Field Development Plan

OIL assumed that the gas condensate fluid would remain in a dense phase and this implied condensate gas ratios ("CGRs") in the range of 20-85 bbl/MMSCF.

The development strategy that OIL has proposed for the Gas Condensate Scenario is to maintain a plateau for 15 years to maximise utilisation of the most expensive assets – the LNG facility and ships.

OIL has assumed an average production rate of 50 MMSCFD for each well as a realistic figure upon which to base the NPV calculations. OIL has also assumed that approximately 5% of recoverable gas would be produced during each of the 15 years on plateau. This implies that a minimum of 75% of the gas would be produced on plateau - a figure at the high end of the typical range for offshore gas developments. OIL has also assumed that each well on average would have a maximum ultimate recovery of approximately 250-270 BCF.

The offshore facilities that OIL has defined utilise, in the main, a standard approach for deepwater developments: wet trees; subsea manifolds and satellite-wells; flexible risers to a dynamically-positioned FPSO with large storage capacity; and a tanker-loading bouy. The FPSO would produce tanker-stabilised condensate and export low dewpoint gas. The only unusual feature of the offshore production facilities would be the large quantity of gas compression power installed on the FPSO, to maintain plateau for 15 years. OIL estimated that a suction-side pressure of 15 bara should recover 75% of the gas on plateau, and this pressure would need to be raised to 135 bara to reach Walvis Bay at around 75 bara. The "Low Estimate" of recoverable resources of the smaller leads benefit from a higher pipeline operating pressure of 220 bara and this has been adopted (the other cases may benefit from similar refinements but their pipeline's proportion of total capex is much smaller so this was not attempted).

4.2.3 Dry Gas Field Development Plan

OIL has assumed that the dry gas fluid has a CGR of 2 bbl/MMSCF. For comparison, Kunene reported a CGR of 1 bbl/MMSCF and Kudu 2 bbl/MMSCF.

The development strategy that OIL has proposed for the Dry Gas Scenario is to maintain a plateau for 15 years to maximise utilisation of the most expensive assets – the LNG facility and ships. The average production rate would be 50 MMSCFD per well; approximately 5% would be produced each year on plateau for a plateau of 15 years; and each well would have a maximum ultimate recovery of 250-270 BCF.

The offshore facilities that OIL has defined utilise, in the main, a standard approach for deepwater developments: wet trees; subsea manifolds and satellite-wells; flexible risers to a dynamically-positioned FPSO with large storage capacity; and a tanker-loading bouy. The FPSO would export low water-dewpoint gas and dry condensate to the LNG facility. Gas compression would be sufficient to maintain the 15-year plateau.

4.2.4 Availability of Facilities

OIL has calculated that a realistic availability of the combined offshore and LNG facilities is 326 days per year. Where there is no gas production to an LNG plant, only gas injection, this rises to 338 days per year.

The significance of these numbers is that extra capital cost is required to deliver a given production volume per year compared with a theoretical facility with 100% availability.

4.3 Cost Estimates and Assumptions

The capital cost estimates for the 63 cases are presented in Table 4.1 to Table 4.7. Other material cost and related assumptions are presented in Table 4.8. Costs related to Fiscal and Licence matters are presented in Section 4.4.2.

Table 4.1 Capital Cost Estimates for the Exploration and Development of Delta Maastrichtian Prospect

	Low Estimate							**Best Estimate**							**High Estimate**						
	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**
	$m	$m	$m	$m	$m	$m	**$m**	$m	$m	$m	$m	$m	$m	**$m**	$m	$m	$m	$m	$m	$m	**$m**
	Volatile Oil																				
Exploration, Appraisal, FEED							**194**							**243**							**308**
Phase 1	2273	1418	992	1315	3803	726	**10527**	2608	1727	1074	1894	6058	1452	**14812**	2905	1926	1173	2710	8522	2483	**19719**
Phase 2								2608	1727	1074	Phase 1	Phase 1	Phase 1	**5409**	2905	1926	1173	Phase 1	Phase 1	Phase 1	**6004**
Phase 3															2905	1926	1173	Phase 1	Phase 1	Phase 1	**6004**
Total Capital Cost	2273	1418	992	1315	3803	726	**10721**	5216	3453	2149	1894	6058	1452	**20464**	8715	5779	3518	2710	8522	2483	**32036**
	Gas Condensate																				
Exploration, Appraisal, FEED							**194**							**243**							**308**
Phase 1	638	374	681	1475	4965	955	**9089**	1192	974	1076	2401	7682	2292	**15617**	1259	892	1041	2401	6977	2101	**14670**
Phase 2															1259	892	1041	2401	6977	2101	**14670**
Total Capital Cost	638	374	681	1475	4965	955	**9282**	1192	974	1076	2401	7682	2292	**15860**	2517	1783	2082	4803	13954	4202	**29649**
	Dry Gas																				
Exploration, Appraisal, FEED							**194**							**243**							**308**
Phase 1	681	376	657	1651	5102	1089	**9555**	1233	971	992	2581	7854	2292	**15923**	1302	890	957	2401	7165	2101	**14816**
Phase 2															1302	890	957	2401	7165	2101	**14816**
Total Capital Cost	681	376	657	1651	5102	1089	**9749**	1233	971	992	2581	7854	2292	**16166**	2604	1779	1913	4803	14331	4202	**29940**

Table 4.2 Capital Cost Estimates for the Exploration and Development of Delta Palaeocene Prospect

	Low Estimate							**Best Estimate**							**High Estimate**						
	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**
	$m	$m	$m	$m	$m	$m	**$m**	$m	$m	$m	$m	$m	$m	**$m**	$m	$m	$m	$m	$m	$m	**$m**
	Volatile Oil																				
Exploration, Appraisal, FEED							**194**							**243**							**308**
Phase 1	1963	1541	1069	1396	4207	726	**10902**	3871	2206	1338	2401	7588	2177	**19581**	5405	2771	1737	4490	16894	4966	**36262**
Phase 2								3871	2206	1338	Phase 1	Phase 1	Phase 1	**7415**	5405	2771	1737	Phase 1	Phase 1	Phase 1	**9912**
Phase 3															5405	2771	1737	Phase 1	Phase 1	Phase 1	**9912**
Total Capital Cost	1963	1541	1069	1396	4207	726	**11095**	7741	4413	2675	2401	7588	2177	**27239**	16214	8313	5210	4490	16894	4966	**56394**
	Gas Condensate																				
Exploration, Appraisal, FEED							**194**							**243**							**308**
Phase 1	666	363	713	1830	5558	1337	**10468**	1822	976	1279	3203	11301	3266	**21847**	2118	1281	1385	3701	13556	3992	**26034**
Phase 2															2118	1281	1385	3701	13556	3992	**26034**
Total Capital Cost	666	363	713	1830	5558	1337	**10662**	1822	976	1279	3203	11301	3266	**22090**	4236	2562	2770	7403	27113	7984	**52376**
	Dry Gas																				
Exploration, Appraisal, FEED							**194**							**243**							**308**
Phase 1	666	363	688	1830	5558	1337	**10443**	1822	965	1164	3203	11301	3266	**21721**	2118	1262	1295	3701	13556	3992	**25925**
Phase 2															2118	1262	1295	3701	13556	3992	**25925**
Total Capital Cost	666	363	688	1830	5558	1337	**10637**	1822	965	1164	3203	11301	3266	**21964**	4236	2524	2590	7403	27113	7984	**52158**

Table 4.3 Capital Cost Estimates for the Exploration and Development of Delta Upper Campanian Lead

	Low Estimate							**Best Estimate**							**High Estimate**						
	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**
	$m	$m	$m	$m	$m	$m	**$m**	$m	$m	$m	$m	$m	$m	**$m**	$m	$m	$m	$m	$m	$m	**$m**
	Volatile Oil																				
Exploration, Appraisal, FEED							**194**							**243**							**272**
Phase 1	636	303	465	584	763	191	**2942**	1151	710	748	813	1898	363	**5682**	2002	1520	923	1099	3650	726	**9920**
Phase 2																					
Phase 3																					
Total Capital Cost	636	303	465	584	763	191	**3136**	1151	710	748	813	1898	363	**5925**	2002	1520	923	1099	3650	726	**10192**
	Gas Condensate																				
Exploration, Appraisal, FEED							**194**							**243**							**272**
Phase 1	193	82	347	467	1064	191	**2343**	328	285	471	704	2744	573	**5105**	634	452	684	1475	4942	955	**9142**
Phase 2																					
Total Capital Cost	193	82	347	467	1064	191	**2537**	328	285	471	704	2744	573	**5348**	634	452	684	1475	4942	955	**9415**
	Dry Gas																				
Exploration, Appraisal, FEED							**194**							**243**							**272**
Phase 1	193	82	338	467	1064	191	**2335**	272	298	497	704	3049	573	**5393**	634	447	641	1475	4942	955	**9094**
Total Capital Cost	193	82	338	467	1064	191	**2528**	272	298	497	704	3049	573	**5636**	634	447	641	1475	4942	955	**9366**

Table 4.4 Capital Cost Estimates for the Exploration and Development of Delta Campanian Wedge Lead

	Low Estimate							**Best Estimate**							**High Estimate**						
	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**
	$m	$m	$m	$m	$m	$m	**$m**	$m	$m	$m	$m	$m	$m	**$m**	$m	$m	$m	$m	$m	$m	**$m**
	Volatile Oil																				
Exploration, Appraisal, FEED							**194**							**243**							**308**
Phase 1	1224	727	762	904	2094	363	**6074**	2574	1740	1084	1894	4361	764	**12417**	2417	1738	1095	1894	6176	1719	**15039**
Phase 2															2417	1738	1095	Phase 1	Phase 1	Phase 1	**5250**
Phase 3																					
Total Capital Cost	1224	727	762	904	2094	363	**6267**	2574	1740	1084	1894	4361	764	**12660**	4834	3476	2190	1894	6176	1719	**20597**
	Gas Condensate																				
Exploration, Appraisal, FEED							**194**							**243**							**272**
Phase 1	325	264	507	813	2927	573	**5408**	620	500	730	1830	5521	1146	**10348**	1439	1053	1159	2581	8074	2483	**16789**
Phase 2																					
Total Capital Cost	325	264	507	813	2927	573	**5602**	620	500	730	1830	5521	1146	**10591**	1439	1053	1159	2581	8074	2483	**17061**
	Dry Gas																				
Exploration, Appraisal, FEED							**194**							**243**							**272**
Phase 1	325	242	493	813	2927	573	**5373**	685	535	690	1830	5583	1337	**10660**	1503	1048	1020	2581	8276	2483	**16911**
Phase 2																					
Total Capital Cost	325	242	493	813	2927	573	**5566**	685	535	690	1830	5583	1337	**10903**	1503	1048	1020	2581	8276	2483	**17183**

Table 4.5 Capital Cost Estimates for the Exploration and Development of Delta Albian Lead

	Low Estimate							**Best Estimate**							**High Estimate**						
	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**
	$m	$m	$m	$m	$m	$m	**$m**	$m	$m	$m	$m	$m	$m	**$m**	$m	$m	$m	$m	$m	$m	**$m**
	Volatile Oil																				
Exploration, Appraisal, FEED							**194**							**243**							**308**
Phase 1	1421	692	776	1029	2558	573	**7049**	2296	1570	1054	1894	6185	1719	**14718**	4011	2107	1354	3701	12319	3629	**27122**
Phase 2								2296	1570	1054	Phase 1	Phase 1	Phase 1	**4920**	4011	2107	1354	Phase 1	Phase 1	Phase 1	**7472**
Phase 3															4011	2107	1354	Phase 1	Phase 1	Phase 1	**7472**
Total Capital Cost	1421	692	776	1029	2558	573	**7243**	4592	3140	2108	1894	6185	1719	**19882**	12032	6321	4063	3701	12319	3629	**42374**
	Gas Condensate																				
Exploration, Appraisal, FEED							**194**							**243**							**308**
Phase 1	387	296	565	1315	3736	726	**7025**	1349	974	1239	2581	7707	2292	**16142**	1691	860	1365	2710	9271	2865	**18762**
Phase 2															1691	860	1365	2710	9271	2865	**18762**
Total Capital Cost	387	296	565	1315	3736	726	**7219**	1349	974	1239	2581	7707	2292	**16385**	3382	1720	2730	5420	18542	5730	**37833**
	Dry Gas																				
Exploration, Appraisal, FEED							**194**							**243**							**308**
Phase 1	433	336	528	1315	3996	726	**7333**	1497	983	1017	2581	8251	2483	**16812**	1889	864	1097	3203	10057	2903	**20012**
Phase 2															1889	864	1097	3203	10057	2903	**20012**
Total Capital Cost	433	336	528	1315	3996	726	**7527**	1497	983	1017	2581	8251	2483	**17055**	3777	1728	2194	6405	20115	5806	**40333**

Table 4.6 Capital Cost Estimates for the Exploration and Development of Alpha Palaeocene Lead

	Low Estimate							Best Estimate							High Estimate						
	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**
	$m	$m	$m	$m	$m	$m	**$m**	$m	$m	$m	$m	$m	$m	**$m**	$m	$m	$m	$m	$m	$m	**$m**
	Volatile Oil																				
Exploration, Appraisal, FEED							**168**							**246**							**311**
Phase 1	1040	600	694	632	1494	363	**4822**	1770	1423	889	1246	3284	573	**9184**	1466	1423	891	1840	5170	1089	**11878**
Phase 2															1466	1423	891	Phase 1	Phase 1	Phase 1	**3779**
Phase 3																					
Total Capital Cost	1040	600	694	FLNG	1494	363	**4990**	1770	1423	889	1246	3284	573	**9430**	2931	2846	1781	1840	5170	1089	**15968**
	Gas Condensate																				
Exploration, Appraisal, FEED							**168**							**246**							**275**
Phase 1	210	233	451	784	2390	363	**4430**	458	387	602	1654	4567	955	**8623**	879	707	854	2304	6223	1719	**12686**
Phase 2																					
Total Capital Cost	210	233	451	784	2390	363	**4598**	458	387	602	1654	4567	955	**8869**	879	707	854	2304	6223	1719	**12961**
	Dry Gas																				
Exploration, Appraisal, FEED							**168**							**246**							**275**
Phase 1	222	181	421	784	2048	363	**4020**	421	383	559	1563	4357	764	**8048**	843	705	803	2304	6158	1528	**12341**
Phase 2																					
Total Capital Cost	222	181	421	784	2048	363	**4188**	421	383	559	1563	4357	764	**8294**	843	705	803	2304	6158	1528	**12617**

Table 4.7 Capital Cost Estimates for the Exploration and Development of Gamma Palaeocene Lead

	Low Estimate							**Best Estimate**							**High Estimate**						
	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**	Wells	Subsea	FPSO + Loading Buoy	Pipeline Walvis Bay	LNG Plant	LNG Ships	**Totals**
	$m	$m	$m	$m	$m	$m	**$m**	$m	$m	$m	$m	$m	$m	**$m**	$m	$m	$m	$m	$m	$m	**$m**
	Volatile Oil																				
Exploration, Appraisal, FEED							**168**							**246**							**311**
Phase 1	1816	1668	938	1397	3660	726	**10204**	2468	1934	1107	2304	6220	1719	**15753**	3497	2336	1350	3996	11126	3247	**25553**
Phase 2								2468	1934	1107	Phase 1	Phase 1	Phase 1	**5509**	3497	2336	1350	Phase 1	Phase 1	Phase 1	**7183**
Phase 3															3497	2336	1350	Phase 1	Phase 1	Phase 1	**7183**
Total Capital Cost	1816	1668	938	1397	3660	726	**10372**	4936	3869	2214	2304	6220	1719	**21509**	10492	7007	4051	3996	11126	3247	**40231**
	Gas Condensate																				
Exploration, Appraisal, FEED							**168**							**246**							**311**
Phase 1	433	235	602	1654	4689	955	**8568**	1177	1073	1109	3228	8288	2483	**17357**	1461	1052	1172	3741	9462	2865	**19753**
Phase 2															1461	1052	1172	3741	9462	2865	**19753**
Total Capital Cost	433	235	602	1654	4689	955	**8735**	1177	1073	1109	3228	8288	2483	**17603**	2923	2104	2345	7482	18923	5730	**39818**
	Dry Gas																				
Exploration, Appraisal, FEED							**168**							**246**							**311**
Phase 1	400	232	564	1654	4492	955	**8297**	1055	1046	987	3095	7682	2292	**16156**	1338	998	1045	3228	8844	2540	**17994**
Phase 2															1338	998	1045	3228	8844	2540	**17994**
Total Capital Cost	400	232	564	1654	4492	955	**8465**	1055	1046	987	3095	7682	2292	**16402**	2676	1996	2090	6456	17689	5080	**36299**

Table 4.8 Other Cost Assumptions

Item	Value	Comments
Cost escalation (%)	2%	US Dollar typical, from 2012
Oil Tanker tariff $/tonne	$12.3	W Africa to US Gulf 260,000 ton (refer Petroleum Argus)
LNG Charter Rate $/day	$50,000	140,000 cu m tanker 2011 charter rate, and long-term typical
LNG Ship speed	20	knots, typical
Distance to Regas Terminal	5422	nautical miles (Walvis Bay to Milford Haven, UK)
LNG Opex (as & of capex)	4%-4.8%	Refer LNGPedia.com for plants of various capacities
LNG Ship Opex (as % of capex)	4.00%	No data but 4% typical of offshore facilities
Drilling Spread Day Rate $/day	$620,000	Survey of drilling contracts
Insurance (as % of capex)	0.50%	Typical for industry
Abandonment (% of total capex) ($m)	10%	Typical for offshore
Abandonment Fund Commences After	50%	Production of total recoverable reserves
Abandonment	2040	End of 25-year production license: 2040
Depreciation (straight line pa)	3	Year
G&A (to first oil)	2.5%	of capex plus $2m pa
G&A Production Phase	1.0%	of gross revenue

4.4 Economic Analysis

NPVs of estimated after-tax cash flows (as at 31st May 2011) attributable to Tower have been calculated at a nominal discount rate of 10% for the two prospects and five leads. OIL's assessment is based upon pricing, cost and inflation assumption presented in Sections 4.2 to 4.4.3.3; and OIL's understanding of the fiscal and contractual terms governing the Licence presented in Section 4.4.2. No adjustments have been made for cash balances, inventories, indebtedness or other balance-sheet items.

The reported hydrocarbon volumes and values are estimates based on professional judgement and are subject to future revisions, upward or downward, as additional information becomes available.

NPVs have been calculated for each of the seven Prospect/Leads for the following matrix of nine cases; i.e. 63 NPV calculations in total for the seven Prospect/Leads.

Prospective Resources	Gas Condensate	Volatile Oil	Dry Gas
Low Estimate	X	X	X
Best Estimate	X	X	X
High Estimate	X	X	X

4.4.1 Project Schedule

OIL has developed a schedule of milestones required to achieve First Production and concluded that 1/1/2020 is realistically achievable, assuming the Production Licence is granted in 2015 (for 25 years to 2040). Where the size of the Lead/Prospect justifies a second phase of investment, it is estimated that this would come on stream in 2025. A third phase would come on stream in 2027.

A realistic production profile for developing these assets would be 25 years, to 2045, and we have valued production to the end of the Licence Period, 2040. The residual value is small.

4.4.2 Fiscal System

OIL has undertaken independent research of the Namibian Tax legislation that applies to Licence 0010, which was signed in August 2005. Table 4.9 refers.

Table 4.9 Tax/Royalty Legislation Applicable to Licence 0010

Tax/Royalty	Rate Applied in Economic Analysis	Comments
Royalty	5%	5% in Clause 13 of 2005 Licence Agreement, "subject to Petroleum Act 1991") (S. 62(1). S 5 of Petroleum Laws Amendment Act 1998 amended S 62(1) (b) of the Petroleum Act 1991 from 12.5% to 5%.
Rental of Land	Exploration N$60 -150 /km2 pa Production: N$ 1500 / km2 pa	(i) 11640 km2 Exploration Licence (ii) Area of Delta and Gamma Production Licences would be around 1500 km2. Alpha would be about 750 km2.
Petroleum Income Tax	35% of "Taxable Income"	S.6 of Petroleum (Taxation) Act 1991 states 42%. However, S 8 of Petroleum Laws Amendment Act 1998 amends to 35%. Clause 14 of Licence 0010 simply refers to Section 5 of Taxation Act and in law this would normally mean "Taxation Act, as Amended", unless otherwise stated/explicitly grandfathered).
Taxable Income		Gross Income Less Allowable Deductions stated in Tax Act 1991 As amended: S 8 (royalties, rents, expenses G&A{world} and interest) and S.9 (Pre-Production Exploration: in 1st year of Production; Pre-Production Development Capex: depreciated over years 1st to 3rd years of production; S.10 similar rules for E&P subsequent to 1st production)
Allowable Losses		S. 18: Full Carry-forward of Losses
Additional Profits tax on: "first accumulated net cash position"	25% of net cash receipts Payable when Real After-Tax rate of return is greater than (AxB) + C}	S 16 of Petroleum Laws Amendment Act 1998 amends the applicable rate of S 21 of the Petroleum Tax Act 1991 to (51.25%-35%)/(100%-35%) = 25%. NB: S 21 of the Petroleum Tax Act 1991 does not define "first accumulated net cash position (or indeed "second accumulated net cash position" and "third accumulated net cash position") BUT Mbendi does (http://www.mbendi.com/indy/oilg/govo/af/na/p0005.htm). Clause 14 of Licence stated that additional profits tax levied on the second and third accumulated net cash positions shall be zero, so only the "first accumulated net cash position is relevant. So, A, B, C are defined as follows A is "first accumulated net cash position"

Tax/Royalty	Rate Applied in Economic Analysis	Comments
		B= (100% + 15% + Inflation) C= "Net Cash Receipts" for the Tax year "Net Cash Receipts" are revenues less allowable
First accumulated net cash position		Cumulative net cash receipts from Licence Award.
Net Cash Receipts		S.1 of Petroleum Tax Act 1991 as amended by S.8 of Petroleum Laws Amendment Act 1998 : Gross Income – Expenses (exc. Loan Interest) – Capex – {Petroleum Income tax} – {Additional Profits Tax arising from the second and third accumulated net cash positions}. (I.e. the additional profits tax arising from the first accumulated net cash position is NOT mentioned in the definition)
Decommissioning Fund		S.7 of Petroleum Laws Amendment Act 1998: a Trust must be started before 50% of recoverable reserves are produced, and be of sufficient value to fund all decommissioning at abandonment or expiration of production Licence. S.10 stipulates that annual contributions are tax deductions in year incurred.
VAT and Customs Duties	15%	Applicable on good supplied or imported
Dividend Withholding Tax	Zero	Clause 14.4 of Licence excludes other taxes being levied on the Licencees.

4.4.3 Commodity Pricing

4.4.3.1 Oil and Condensate Pricing

Potential markets for liquids would include South Africa (for small volumes), the US or Europe. There is little difference in commodity pricing or tanker tariffs to the latter two, and the ICE Brent Futures slate to 2019 dated 31st May 2011 was adopted. For the Gas Condensate and Dry Gas Scenarios, the liquids would be of higher quality than Brent, and OIL estimates a $1.5/barrel premium. For the Volatile Oil Scenario, the liquids would be of a similar quality to Brent and probably would not attract a premium. Table 4.10 refers. An escalation rate of 2% pa was applied to oil prices from 2020 to perpetuity.

Table 4.10 ICE UK Brent Futures Slate 31/5/11 (Year Average)

Period	Avg Price	Change	Change
	$/bbl	$/bbl	%
2011 H2	$110.00		
2012	$113.27	$3.27	3.0%
2013	$109.70	-$3.57	-3.2%
2014	$106.53	-$3.17	-2.9%
2015	$104.80	-$1.73	-1.6%
2016	$104.23	-$0.57	-0.5%
2017	$104.21	-$0.02	0.0%
2018	$104.47	$0.26	0.2%
2019	$104.97	$0.50	0.5%

4.4.3.2 Gas Pricing

Potential markets for large gas volumes would include USA and Western Europe. However Nymex Henry Hub Futures have been consistently lower than ICE UK Gas Futures since at least 2009 and so the latter price slate to 2017 dated 31st May 2011 was adopted. Table 4.11 refers.

The transportation distances from Walvis Bay to Milford Haven, UK vs. Maryland, USA are also lower (5400nm vs. 6400 nm).

An escalation rate of 2% pa was applied from 2018 to perpetuity.

Table 4.11 ICE UK Gas Futures Slate 31/5/11 (Year Average)

Year	Avg Price	Change	% Change
	$/MMBTU	$/MMBTU	%
2011 H2	$10.62		
2012	$11.43	$0.81	7.6%
2013	$11.75	$0.32	2.8%
2014	$11.97	$0.22	1.9%
2015	$12.19	$0.22	1.8%
2016	$12.40	$0.21	1.7%
2017	$12.59	$0.19	1.5%

4.4.3.3 Exchange Rates and Cost Inflation

Table 4.12 refers.

Table 4.12 Exchange rates used in this CPR

Currency	Exchange Rate	Date
USD/Pound Sterling	1.6451	31/5/11
USD / Namibian Dollar	0.1440	31/5/11
Euro / Namibian Dollar	0.10100	31/5/11
Euro / US Dollar	1.43950	31/5/11

A cost escalation factor of 2% pa from 2012 was applied.

4.4.4 Expected Monetary Values

Expected Monetary Values (EMVs) have been calculated for the two Prospects and the five Leads, and summary results are presented in Table 0.6. The calculation procedure is as follows:

(I) Section 4.1 reported that NPVs were calculated for each of the seven Prospect/Leads for a matrix of nine cases.

(II) The NPV used in the EMV calculation for each Prospect/Lead is a weight-average of both the distribution of NPVs by Prospective Resource Estimate and by Reservoir Fluid Type, as follows:-

a. Swanson's Rule; i.e.: 0.3*NPV(Low Estimate) + 0.4*NPV(Best Estimate) + 0.3* NPV(High Estimate); and
b. The relative probability that the Prospective Resources are charged with Volatile Oil, Gas Condensate and Dry Gas; Table 4.13 refers.

Table 4.13 Fluid Probabilities for the Leads

Fluid Type	Delta Prospects and Leads	Alpha, Gamma and Inter-structural Areas
Dry Gas	10%	11%
Gas Condensate	40%	44%
Volatile Oil	50%	45%
Total	100%	100%

(III) The Economic Chances of Success ("ECOS") is the probability that a discovery, having achieved the threshold of becoming a Contingent Resource, will evolve into an economic field development.

ECOS' for each development scenario (e.g.: "Delta Albian, Low Estimate, Dry Gas") were calculated from the Geological Chance of Success by applying an Economic Probability:

ECOS = GCOS x Economic Probability

The Economic Probability for each development scenario was estimated as follows.

(III-1) A blanket Economic Probability of 90% was applied to all development scenarios to reflect the following economic risks potentially relevant to this project:

- Future oversupply of gas (or LNG) worldwide
- Future competition from cheaper hydrocarbon provinces, e.g. shale gas, Iraq, Iran etc
- The very large capital costs
- Although Namibia is one of the most stable regimes in Africa, political instability (or necessity) could lead to e.g. unilateral change in Licence terms.

(III-2) The 90% Probability was potentially reduced further with reference to the IRR of the development scenario, under a stress test of 70% commodity prices plus 130% capital and operating costs; Table 4.14 refers. The Economic Probabilities for the prospects and leads are presented in Table 0.7.

Table 4.14 Economic Probability vs. Development Scenario IRR under Stress Test

IRR	Economic Probability
>15%	90%
10%-15%	80%
5%-10%	60%
<5%	20%

(IV) The Expected Monetary Values were calculated according to the formula:

EMV = ECOS*NPV – (1 - ECOS)*Cost of Failure.

(V) The Cost of Failure was calculated as Tower's attributable contribution to the cost of seismic, exploration and early appraisal including Opex and G&A; each lead was considered on a stand-alone basis.

The EMVs presented in Table 0.6 are based on OIL's understanding of the current petroleum legislation, taxation and other regulations pertaining to Namibia (refer Section 4.4.2). It is also based on a forecast from 2020 to 2040 of oil prices in USA and gas prices in Western Europe (refer Section 4.4.3). It is emphasised that legislation, taxation and commodity-price forecasts can be subject to significant change even in the short term and that any of these could have a significant effect on the NPVs and EMVs presented in this CPR.

The reported hydrocarbon volumes and values are estimates based on professional judgement and are subject to future revisions, upward or downward, as additional information becomes available. The NPVs and EMVs presented in this CPR do not represent OIL's opinion of the open market value of Tower's Namibian Petroleum Assets. OIL does not confirm Tower's legal right to title in Licence 0010; the detail or the enforceability of Tower's original farm-out agreement with Arcadia; and the absence or nature of any liens or other encumbrances that might affect Tower's rights to, or value in, Licence 0010.

Appendix I SPE Petroleum Resource Management System

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

Definitions and Guidelines, 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
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: completion intervals which are open at the time of the estimate but which have not yet started producing, wells which were shut-in for market conditions or pipeline connections, or install production or transportation facilities for primary or improved recovery Projects or 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 complete an existing well.

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.