OIL BASINS LIMITED
ABN 56 006 024 764

23 November 2011

Company Announcements Office
Australian Stock Exchange Limited
10th Floor, 20 Bond Street
Sydney NSW 2000

Dear Sirs

BACKREEF AREA PROSPECTIVE RESOURCES

The Directors of Oil Basins Limited (**OBL**, ASX codes **OBL**, **OBLOA** and **OBLOB,** or the **Company**) are pleased to make the following ASX announcement as a matter of record so as to keep the market fully informed about a significant independent re-assessment of the prospectivity of its Backreef Area interests in the Fitzroy Trough region of the Canning Basin, Western Australia – OBL net 100% beneficial interest.

Following the collection of previously recorded 2D seismic data of various vintages, Dayboro Geophysical Pty Ltd reprocessed original field data deriving PSTM and PSDM seismic outputs. The Company using this PSDM data completed its interpretation of the potential New Oil Play within the Backreef Area using advanced Schlumberger Petrel™ seismic interpretation software (refer to OBL ASX Release 30 August 2011).

In September the Company engaged RPS Energy Services Pty Ltd ("RPS") to prepare an Independent Resource Evaluation Report to assess the following:

- Petrophysical analysis of electric logs from Backreef-1,
- Independent interpretation of prospect mapping using Petrel™ software
- Definition of possible new leads within the possible Backreef Area
- Recommendations for future work

This Resource evaluation covers the hydrocarbon Resources in the Canning Basin permits L6, EP129 R2 and EP129 R3 in which the OBL Group has a 100% interest via wholly owned subsidiaries. RPS made Low, Best and High estimates of Prospective Resources as of 1st October, 2011.

The Resource estimates in the Report and Summary (see attached) are in accordance with standard petroleum engineering techniques and using the March 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System **(PRMS)**.

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KEY POINTS

- **RPS Energy Pty Ltd (RPS) has completed an independent comprehensive technical review of the Backreef-1 well result and the recent OBL interpretation of the previously assessed New Oil Play within the Backreef Area**

- **Using its own assessment of Backreef petrophysics and its own mapping of New Oil Play, RPS has concluded in accordance with strict PRMS guidelines that the Backreef Area could host a significant aggregated undiscovered potential Oil in Place (OIP) volume of between 45.6 to 117 MMbbls with an expectation of 77.7 MMbbls and a mean estimate of 20.6 MMbbls Prospective Resources.**

- **Eight (8) Leads have been independently derived by RPS within the southern and south-eastern portions of the Company's Backreef Area.**

- **Four (4) Leads have potential to be larger than the Blina Oil Field which has an initial OIP of circa 5.7 MMbbls (with circa 1.9 MMbbls produced since 1981) and is the largest field so far discovered within this region of the Fitzroy Trough).**

- **Two newly mapped stratigraphic Leads, notably Lead E and Lead F, are potentially large with indicative areas greater than 4 km^2. RPS has delineating a gross recoverable Prospective Resource greater than 5 MMbbls for these two Leads.**

RPS Assessment of New Oil Play

The RPS assessment in accordance with PRMS is summarised in the attached Letter to Oil Basins Limited dated 22 November 2011 and investors are reminded to refer to the key assumptions and Glossary of definitions in this Letter.

RPS undertook a horizon and fault interpretation of the 2D seismic data using Schlumberger Petrel^{TM} seismic interpretation software. The previously recorded seismic data of various vintages were reprocessed from original field data in 2011 by Dayboro Geophysical Pty Ltd. PSDM data (derived from PSTM) was used for interpretation **(Figure 1).** RPS considered the seismic data quality to be generally sufficient to delineate the two primary reservoir intervals (Yellow Drum Formation and Nullara Limestone). However the sparse 2D seismic coverage was not sufficient to detail faults and structural closures with certainty so only Leads were defined.

RPS Delineated Leads within the Backreef Area

In brief the conclusions of RPS independent assessment (see attached) can be summarised in **Figure 2** and **Tables 1 and 2** – specific features of the Leads defined by RPS are detailed as follows:

- **Lead A (East Blina Lead)** is a Top Yellow Drum Formation structural rollover observed on one seismic line, BV93-17 and is located approximately 3 km east and updip of the Blina field, and 4 km west of Backreef-1. Mapped P50 area and volumes – area 0.359 km^2, GRV 19.7 km^2.m and Undiscovered OIP 1.86 MMstb

- **Lead Backreef** is a Top Yellow Drum Formation structural rollover observed on one seismic line, BV93-17 and is located approximately 6 km east and updip of the Blina field, and includes the Backreef-1 well notionally on the edge of possible mapped closure. Mapped P50 area and volumes – area 0.226 km^2, GRV 12.4 km^2.m and Undiscovered OIP 1.17 MMstb.

- **Lead B** is a Top Yellow Drum Formation structural rollover observed on one seismic line, BV93-16 and is located approximately 5 km east and updip of the Blina field, and 2 km southeast of Backreef-1. Mapped P50 area and volumes – area 0.421 km^2, GRV 23.1 km^2.m and Undiscovered OIP 2.18 MMstb

- **Lead C** is a Top Yellow Drum Formation structural rollover observed on one seismic line, H80-56 and is located approximately 4 km northeast and updip of the Blina field, and 5 km northwest of Backreef-1. Mapped P50 area and volumes – area 0.288 km^2, GRV 15.8 km^2.m and Undiscovered OIP 1.49 MMstb

- **Lead D** is a Top Yellow Drum Formation structural rollover observed on one seismic line, H84-0573, and is located approximately 6.5 km north of Mariana-1. Mapped P50 area and volumes – area 1.23 km^2, GRV 67.4 km^2.m and Undiscovered OIP 6.37 MMstb

- **Lead E** is a Top Yellow Drum Formation stratigraphic trap closed against a channel incision, and observed on three seismic lines. It is located approximately 8 km northeast of Mariana-1 and 7 km northwest of Harold-1 and relies on lateral seal being provided by shale-filled channels. Mapped P50 area and volumes – area 4.12 km^2, GRV 226 km^2.m and Undiscovered OIP 21.3 MMstb

- **Lead F** is a Top Yellow Drum Formation stratigraphic trap closed against a channel incision, and observed on three seismic lines. It is located approximately 1.5 km east of Backreef-1. Mapped P50 area and volumes – area 5.96 km^2, GRV 327 km^2.m and Undiscovered OIP 30.9 MMstb

- **Lead G** is a Top Nullara Limestone structural rollover observed on one seismic line, H84-073, and is located approximately 10 km northeast of Blina, 2.5 km north of Backreef-1, and 3 km south of Harold-1. Lead G partly underlies the Yellow Drum Formation Lead F. Nullara Limestone was not reported to be present in Backreef-1, but was reported in Harold-1 and Mariana-1 with shows. Mapped P50 area and volumes – area 1.27 km^2, GRV 73.7 km^2.m and Undiscovered OIP 8.93 MMstb

RPS has also determined the probability distribution for the overall Prospective Resources total in **Figure 3**.

Oil Basins Comments

The Backreef Area is undoubtedly a good and highly prospective hydrocarbon address.

The Company is delighted that this independent peer review has defined an inventory of Leads within the hitherto under-explored Backreef Area which are potentially both prospective and importantly situated at relatively shallow depth (less than 1,000mTVDss) and therefore relatively cheap to both drill and complete.

Investors should note that the RPS petrophysically identified net pay of circa 12m in Backreef-1, is considerably smaller than the net pay of circa 40m from earlier Weatherford petrophysics analysis. RPS's seismically mapped closure is smaller than OBL's log-interpreted closure, and in addition due to strict PRMS guidelines specifically ignores any potential stratigraphic trap potential in the immediate vicinity of Backreef-1 (captured updip via Lead F).

In OBL's opinion, the proposed cased hole production test at Backreef-1 will provide sufficient downhole information to resolve the assumption differences between Weatherford and RPS and if the test is successful, a suitably designed and located appraisal well (ie Backreef-2) in the first instance followed by modern 2D seismic will definitely determine the stratigraphic and/or structural nature of the Backreef Lead and better define the definition and closures of all Leads

It's very likely that if not from the same deepened well bore, Leads F and G can be drilled from the same drilling pad.

The Company believes this new work constitutes a major independent geophysical and geological assessment and 'expert peer review' of the prospective resources potentially within the Kimberley Downs Embayment feature contained within of the Backreef Area.

The Company is greatly encouraged by the RPS peer review and intends to immediately follow-up on a number of their recommendations in the 2012 work program, to further reduce uncertainties in the asset; namely

- Test Backreef-1 to confirm the fluid content, permeability and hydrocarbon productivity of the reservoir.

- If the test is successful, drill a better positioned step-out Backreef-2 appraisal well to recover cores of the reservoir and define the OWC and/or deviate into thicker reservoir section, and

- Should the Backreef-1 cased hole production test be successful, consider shooting modern 2D seismic to determine the stratigraphic and/or structural nature of the Backreef Lead and better define the definition and closures of all Leads

If future exploration is successful in this New Oil Play Area within the Backreef Area is likely to be a 'Company Maker' for OBL, given its high beneficial ownership (OBL net 100%).

Additional Prospective Resource Potential

The deeper unconventional shale gas **(USG)** potential of the Kimberley Downs Embayment was not re-assessed in this new RPS study of which was limited to assessing the prospective resources potential of the New Oil Play only.

The unrisked potential gross 'gas in place' USG resources was previously independently assessed at between 4.3 Tcf to 21.3 Tcf GIP (refer to OBL ASX Release 8 July 2010).

Yours faithfully

Neil F. Doyle

Neil F. Doyle SPE
Director & CEO

GLOSSARY & PETROLEUM UNITS

bbl (or b)	barrel of oil which in volume terms is equivalent to 159 litres
CSG	Coal seam gas
EUR	Expected ultimate recovery
G&G	Geological and geophysical
GIP	Gas in place
MM	Million
OIP	Oil in place
OWC	Oil water contact
PBTD	Plugged back total depth
PRMS	Petroleum Resource Management System **(PRMS)** Guidelines developed by the Society of Petroleum Engineers **(SPE)** for the reporting of hydrocarbon volumes.
PSTM	Pre-stack time migration – reprocessing method used with seismic.
PSDM	Pre-stack depth migration – reprocessing method used with seismic converting time into depth.
USG	Unconventional shale gas

Refer also to the PRMS definitions in the attached RPS Energy Letter.

CONSENTS

The technical information quoted has been complied and / or assessed by Company Director Mr Neil Doyle who is a professional engineer (BEng, MEngSc - Geomechanics) with over 29 years standing and has been a continuous member of the US Society of Petroleum Engineers (SPE) since 1981 and Mr Geoff Geary BSc (Geology) with over 32 years standing and is a member of the Petroleum Exploration Society of Australia (PESA).

The prospective geophysical and reservoir technical data relating to the Backreef Area, Canning Basin has been independently assessed by RPS Energy and reported to the Company on 21 November 2011.

Both Mr Doyle, Mr Geary and RPS have consented to the inclusion in this announcement of the matters based on the information in the form and context in which they appear.

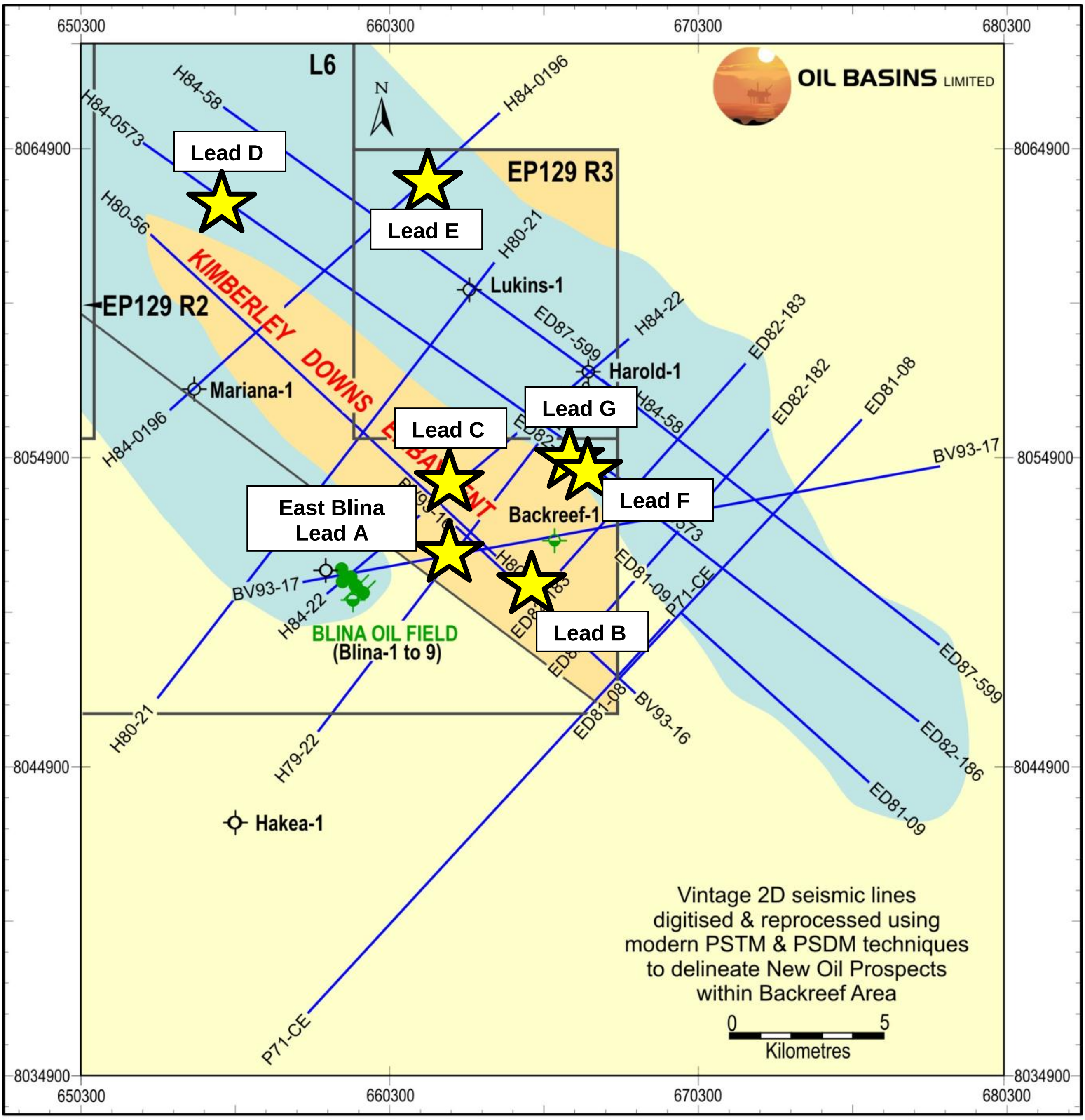

Figure 1

Vintage 2D seismic lines digitised and reprocessed within Backreef Area – OBL 100% Rights

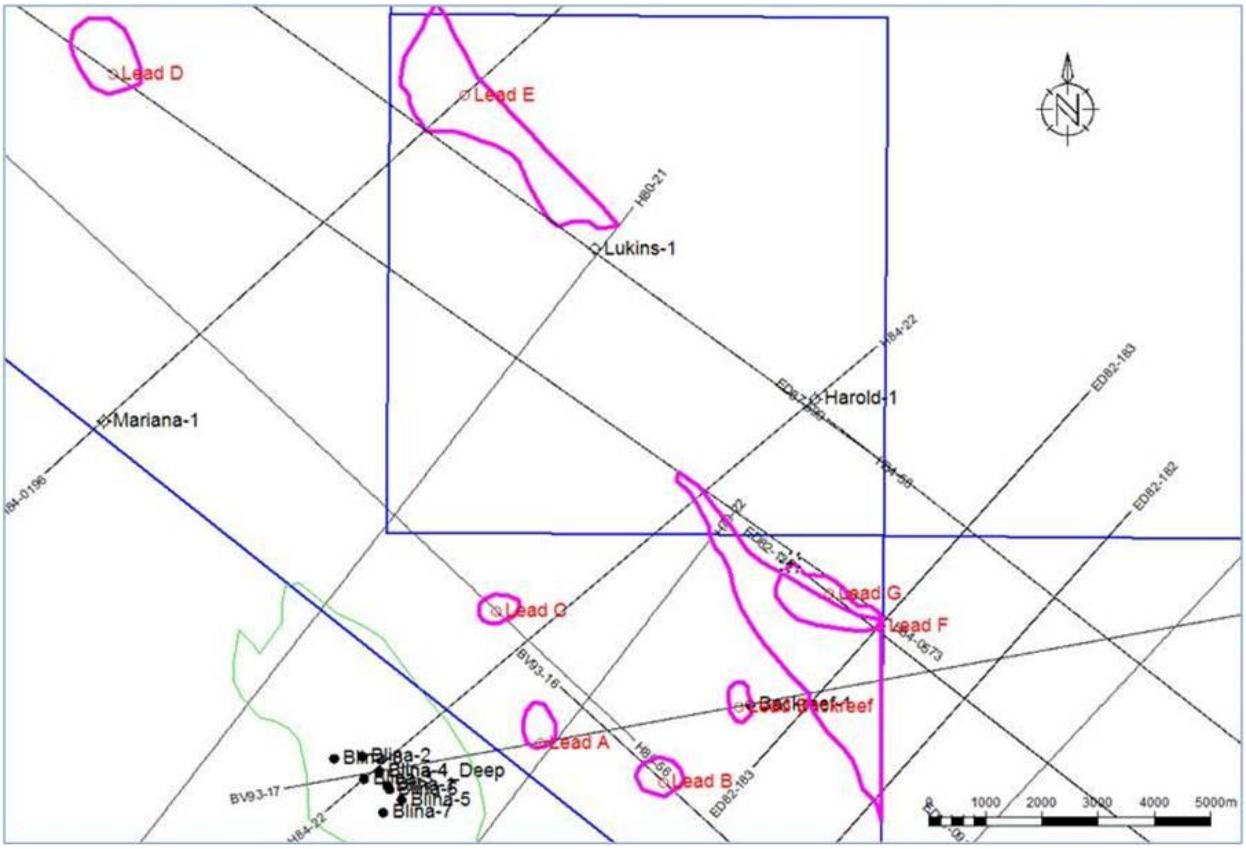

Figure 2
RPS assessed Leads within Backreef Area – OBL 100% Rights

Lead	Target	Undiscovered OIP MMbbls				
		P90	P50	P10	Mean	GPoS
East Blina (Lead A)	Yellow Drum	1.00	1.86	3.08	**1.97**	8
Backreef	Yellow Drum	0.63	1.17	1.94	**1.24**	12
B	Yellow Drum	1.18	2.18	3.61	**2.31**	8
C	Yellow Drum	0.81	1.49	2.47	**1.58**	6
D	Yellow Drum	3.44	6.37	10.6	**6.75**	8
E	Yellow Drum	11.5	21.3	35.4	**22.6**	4
F	Yellow Drum	16.7	30.9	51.2	**32.7**	4
G	Nullara	3.86	8.93	16.8	**9.79**	6
Probabilistic Total		**45.6**	**72.8**	**117.0**	**77.7**	

Table 1
Backreef Area – Undiscovered Oil Initially in Place Volumes (100% Basis)

Lead	Target	Prospective Resources MMbbls				
		Low Estimate	Best Estimate	High Estimate	Mean Estimate	GPoS
East Blina (Lead A)	Yellow Drum	0.18	0.47	0.96	**0.49**	8
Backreef	Yellow Drum	0.11	0.29	0.60	**0.31**	12
B	Yellow Drum	0.21	0.55	1.12	**0.58**	8
C	Yellow Drum	0.15	0.37	0.77	**0.40**	6
D	Yellow Drum	0.62	1.59	3.29	**1.69**	8
E	Yellow Drum	2.07	5.33	11.0	**5.65**	4
F	Yellow Drum	3.01	7.73	15.9	**8.18**	4
G	Nullara	0.70	2.23	5.21	**2.45**	6
Probabilistic Total		**8.95**	**17.7**	**35.7**	**20.6**	

Table 2
Backreef Area –Prospective Resource Volumes (100% Basis)

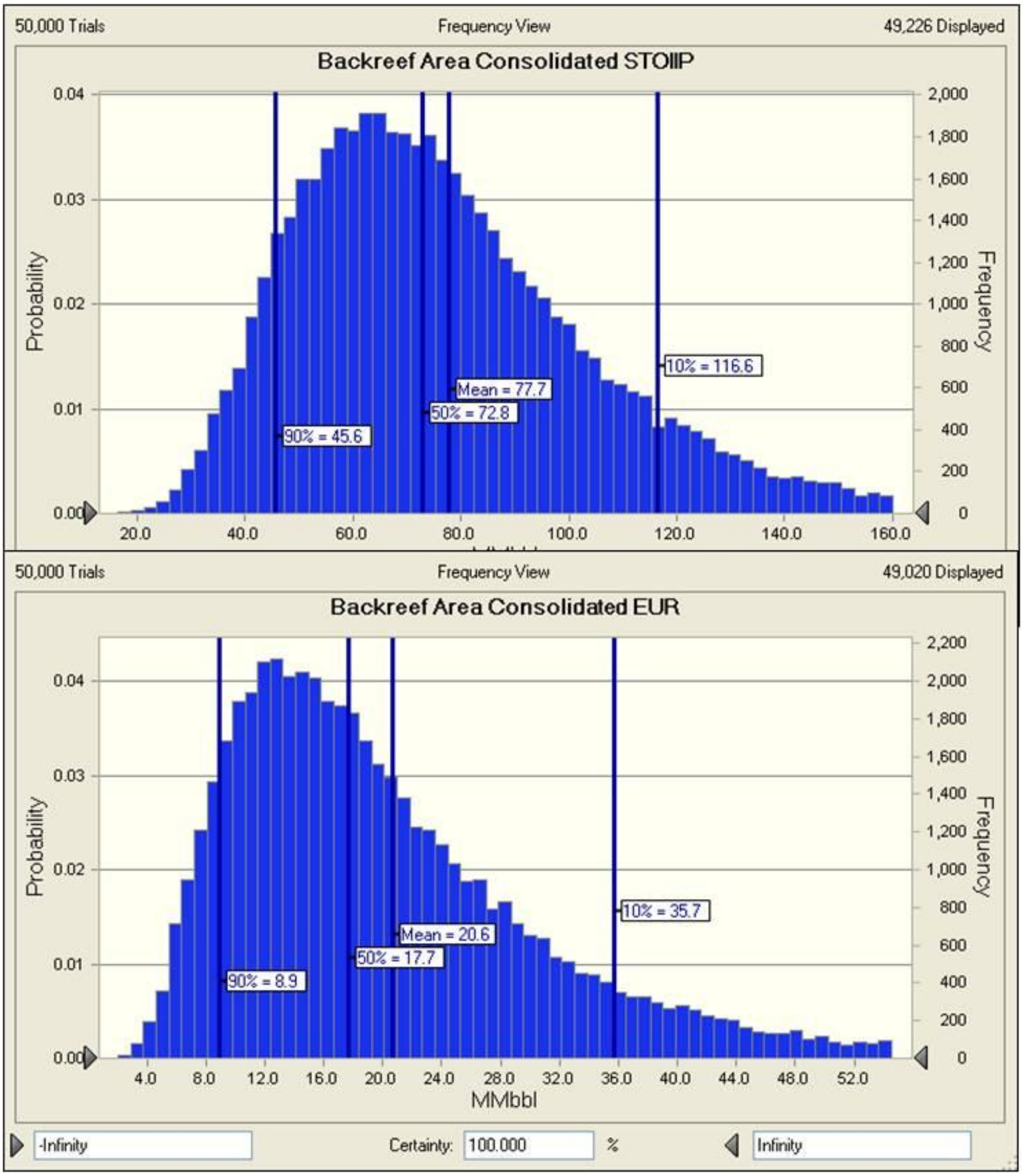

Figure 3
RPS assessed probability distribution for the overall Prospective Resources within the Backreef Area

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Project No: ACI04319 **Date:** 22nd November 2011

Oil Basins Limited

Suite 304, 22 St Kilda Rd,

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Australia

Re: Independent Resource Evaluation Report Backreef Area, L6 and EP129 R2/3, Canning Basin, Australia

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In response to Oil Basin Limited's request of September 2011 and the Letter of Engagement dated 1st October 2011 with Oil Basin Limited ("OBL" or "Company") , RPS Energy Services Pty Ltd (''RPS'') has prepared an Independent Resource Evaluation Report.

This Resource evaluation covers the hydrocarbon Resources in the Canning Basin permits L6, EP129 R2 and EP129 R3 in which the OBL Group has a 100% interest via wholly owned subsidiaries. We have made Low, Best and High estimates of Prospective Resources as of 1st October, 2011. The Resource estimates in this report are in accordance with standard petroleum engineering techniques and using the March 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS).

The work was undertaken by a team of geoscientists, petrophysicists, and petroleum engineers, and is based on data supplied by OBL. Our approach has been to review the data supplied by OBL for reasonableness and then independently estimate ranges of in-place and recoverable volumes. We have estimated the degree of uncertainty inherent in the measurements and interpretation of the data and have calculated a range of recoverable volumes, based on predicted field performance for the property.

The "Backreef Area" is located in the Canning Basin to the east of the Blina oil field (oil production from the Yellow Drum Formation and Nullara Limestone) and other oil discoveries, and consists of three, permits EP129 R2, L6, and EP129 R3, which cover an area of 379 km^2. Previous wells in these permits did not record any hydrocarbon indications. However, OBL drilled the Backreef-1 well in 2010, which had some oil pay indicated by wireline logs and weak shows. The potential hydrocarbons are reservoired within the Yellow Drum Formation which consists of layers of dolomitised carbonates with good indicated porosity but of unknown permeability.

The evaluation of the wireline logs is ambiguous, with the RPS and Weatherford results showing considerable differences. Evaluated logs and reservoir average properties for Backreef-1 were independently calculated by RPS. RPS's evaluation of the interval 917 – 994 m MD was found to contain 12.1 m of net pay, with the major pay accumulation (6.8 m) centred between 956.7 and 963.5 m MD in the Yellow Drum Fm. This compares to the 9 m producible zone within the Yellow Drum Formation in the Blina Field (Figure 1). By way of comparison Weatherford, using their independent petrophysical assumptions and Petrolog CPX software analysis, determined “a possible net pay interval of around 39.2 m and a conservative moveable oil interval within the tight dolomites of around 3.9 m in the Yellow Drum / Gumhole formations”.

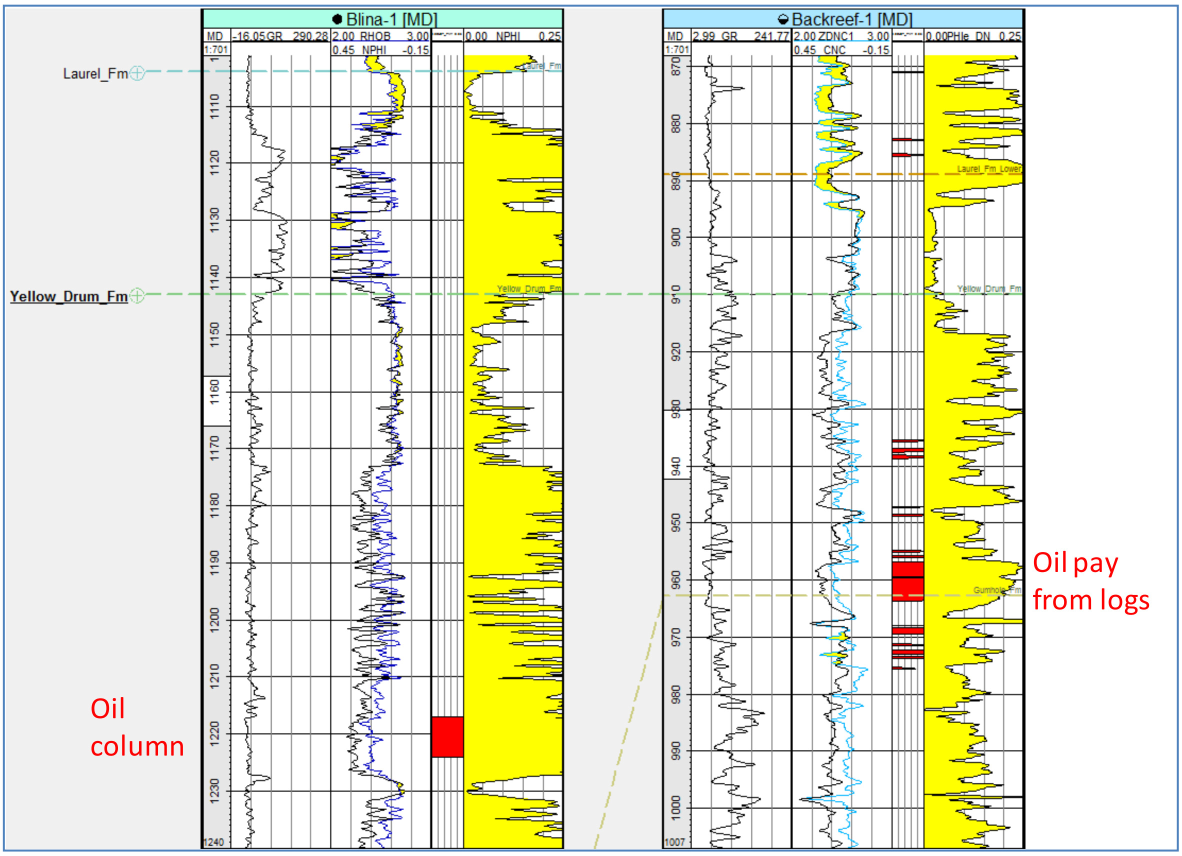

Figure 1: Oil Column in Blina Compared to. Estimated Pay from Wireline Logs in Backreef-1

The structure penetrated at the well location is highly uncertain, due to the sparseness and limitation of the 2D seismic data. To date, the potential pay is untested, but OBL have flagged their intention to re-enter the well during Q2 2012 in order to conduct a test, which may reduce uncertainty in the amount of pay and log evaluation. In the event of a successful test, structure remains as a key uncertainty.

The Blina Field has produced approximately 1.87 MMbbl oil, with most of the production being from the Nullara reservoir. Data available in the literature on similar reservoirs, drive mechanism and oil quality to the Blina Field generally show recovery factors in the range of 18 to 31 per cent, with a mean value of 25 per cent. This range of recovery factors has been considered appropriate for estimation of Prospective Resources in the Backreef area.

Prospects

Horizon interpretation was supplied by OBL. However, due to bulk shift adjustments and well tie insights, RPS undertook a horizon and fault interpretation of the 2D seismic data using Petrel™. The vintage seismic data had been digitised and reprocessed in 2011 by Dayboro Geophysical Pty Ltd and derived PSDM data was used for interpretation. The sparse 2D seismic coverage under-sampled both the structural configuration, and also the fault correlation. The seismic data quality was generally sufficient to delineate the two primary reservoir intervals (Yellow Drum Formation and Nullara Limestone) on the seismic lines.

Inclusive of Backreef-1 which is still a Lead under PRMS guidelines as it is only delineated by a single seismic line, a total of eight Leads have been independently interpreted by RPS within the southern and south-eastern portions of the Company's Backreef Area (Figure 2).

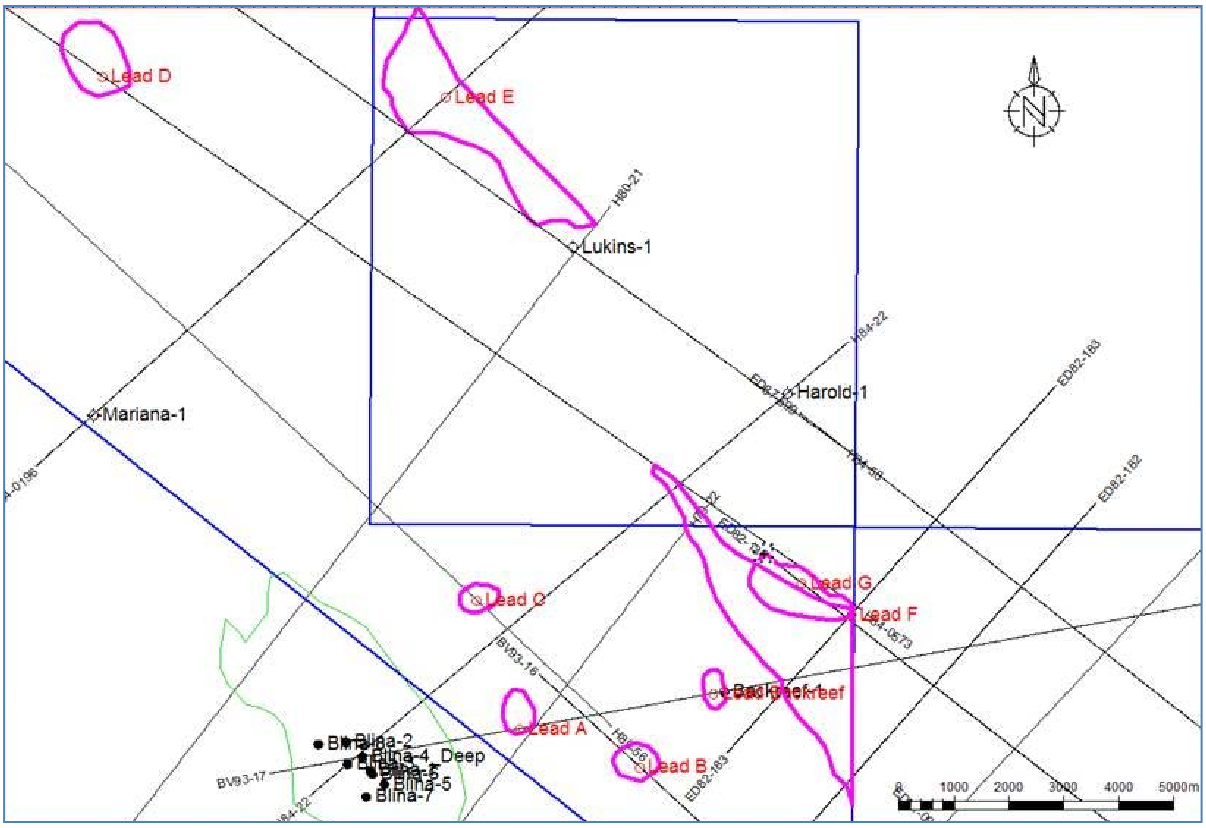

Figure 2: Leads Identified in the L6 and EP129 R2/R3 Permit Areas

Utilising the reprocessed vintage 2D seismic data, although sparse in distribution, allows identification of a number of possible closures based on one line rollover features. A total of seven (7) leads have been identified at the Yellow Drum Formation level (Figure 3), and one (1) lead has been identified at the Nullara Limestone level (Figure 4). There was no Nullara Limestone reported in Backreef-1, however the May River unit may be equivalent, which had limestone inter-beds present.

These leads have been evaluated for Geological Probability of Success ("GPoS") and success case oil volumes. The Gross Petroleum Initially-in-Place and Prospective Resource estimates are shown in Table 1 and have a wide range of uncertainty due to the low density of data.

The structural configuration of all leads is poorly defined by the sparse 2D seismic. Although the existing wells were drilled on mapped four-way dip closures, there is no certainty that the structures were actually closed at the well locations given the poor seismic coverage. Some of the prognosed Leads including Backreef-1 may in fact be stratigraphic or structural in nature but will require modern 2D seismic to adequately define.

Reservoir quality has yet to be demonstrated by a test at Backreef-1, although there has been some production at Blina. Oil charge is expected to most likely occur from the southwest, and the leads are positioned updip from Blina. However, the assumed permeable dolomitic reservoir would need to be regionally extensive and would need to be confirmed by either new stratigraphic coring and/or additional modern 2D seismic.

Seal should be provided by intra-formational permeability changes, and ultimately by marls in the lower Laurel Formation. Seals in the larger mapped stratigraphic Leads E and F are higher risk as they rely upon lateral seals by assumed shale filling of the seismically-inferred channels occurring in the east of the Backreef Area.

It may be possible to locate the exploration well to test both Leads F and G in a single deeper well.

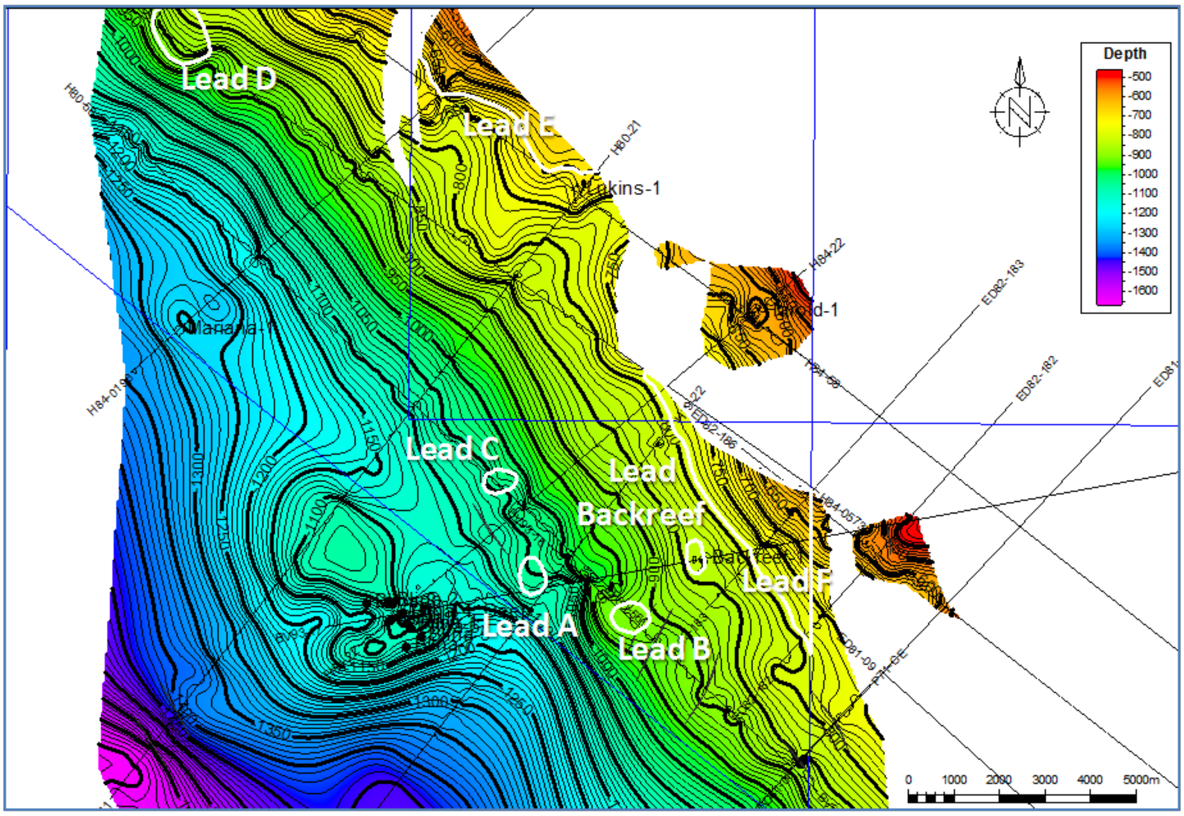

Figure 3: Yellow Drum Fm. Leads Identified Within L6 and EP129 R2/3

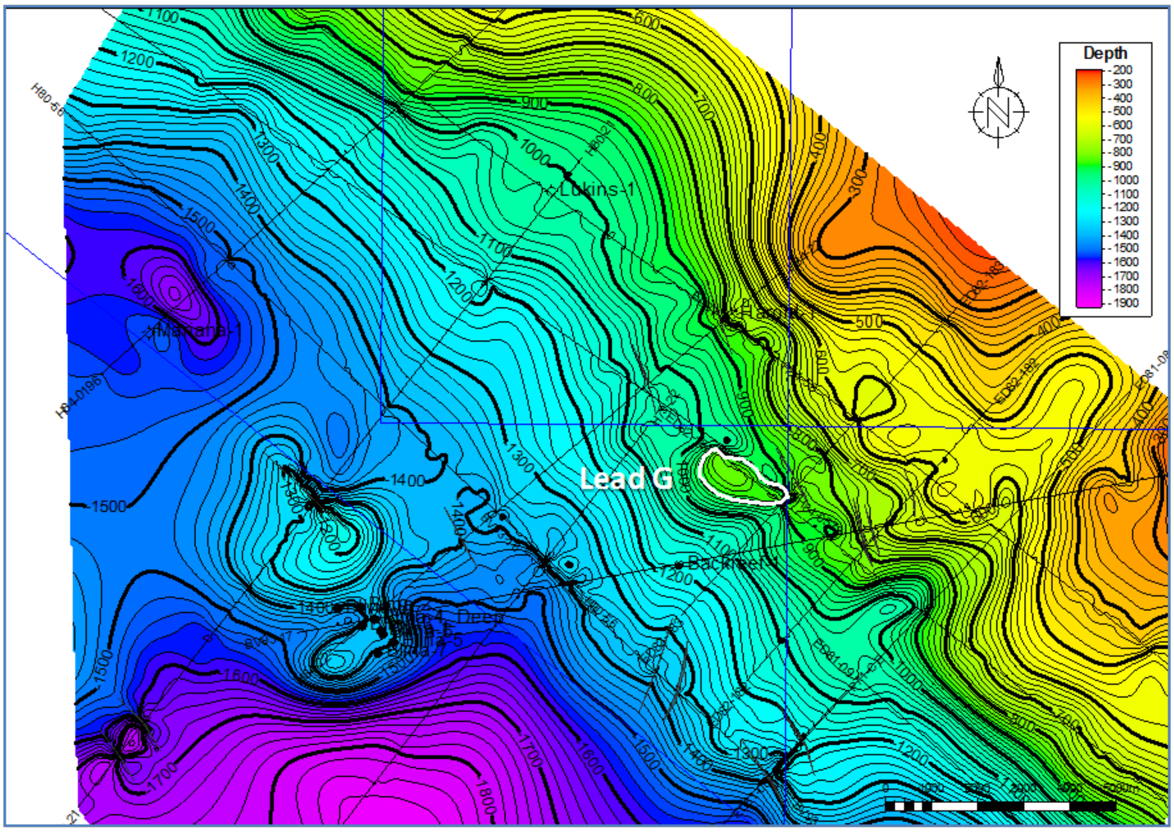

Figure 4: Nullara Lst. Leads Identified Within L6 and EP129 R2/3

Lead A (East Blina) is a Top Yellow Drum Formation structural rollover observed on one seismic line, BV93-17 and is located approximately 3 km east and updip of the Blina field, and 4 km west of Backreef-1. Mapped P50 area and volumes are: area 0.359 km^2, GRV 19.7 km^2.m and Undiscovered STOIIP 1.86 MMstb.

Lead Backreef is a Top Yellow Drum Formation structural rollover observed on one seismic line, BV93-17 and is located approximately 6 km east and updip of the Blina field, and includes the Backreef-1 well notionally on the edge of mapped possible closure. Mapped P50 area and volumes are: area 0.226 km^2, GRV 12.4 km^2.m and Undiscovered STOIIP 1.17 MMstb.

Lead B is a Top Yellow Drum Formation structural rollover observed on one seismic line, BV93-16 and is located approximately 5 km east and updip of the Blina field, and 2 km southeast of Backreef-1. Mapped P50 area and volumes are: area 0.421 km^2, GRV 23.1 km^2.m and Undiscovered STOIIP 2.18 MMstb.

Lead C is a Top Yellow Drum Formation structural rollover observed on one seismic line, H80-56 and is located approximately 4 km northeast and updip of the Blina field, and 5 km northwest of Backreef-1. Mapped P50 area and volumes are: area 0.288 km^2, GRV 15.8 km^2.m and Undiscovered STOIIP 1.49 MMstb.

Lead D is a Top Yellow Drum Formation structural rollover observed on one seismic line, H84-0573, and is located approximately 6.5 km north of Mariana-1. Mapped P50 area and volumes are: area 1.23 km^2, GRV 67.4 km^2.m and Undiscovered STOIIP 6.37 MMstb.

Lead E is a Top Yellow Drum Formation stratigraphic trap closed against a channel incision, and observed on three seismic lines. It is located approximately 8 km northeast of Mariana-1 and 7 km northwest of Harold-1 and relies on lateral seal being provided by shale-filled channels. Mapped P50 area and volumes are: area 4.12 km^2, GRV 226 km^2.m and Undiscovered STOIIP 21.3 MMstb.

Lead F is a Top Yellow Drum Formation stratigraphic trap closed against a channel incision, and observed on three seismic lines. It is located approximately 1.5 km east of Backreef-1. Mapped P50 area and volumes are: area 5.96 km^2, GRV 327 km^2.m and Undiscovered STOIIP 30.9 MMstb.

Lead G is a Top Nullara Limestone structural rollover observed on one seismic line, H84-073, and is located approximately 10 km northeast of Blina, 2.5 km north of Backreef-1, and 3 km south of Harold-1. Lead G partly underlies the Yellow Drum Formation Lead F. Nullara Limestone was not reported to be present in Backreef-1, but was reported in Harold-1 and Mariana-1 with shows. Mapped P50 area and volumes are: area 1.27 km^2, GRV 73.7 km^2.m and Undiscovered STOIIP 8.93 MMstb.

Lead	Undiscovered Oil Initially-In-Place (MMstb)				Prospective Resources (MMstb)				GPoS (%)
	P90	P50	P10	Mean	Low Estimate	Best Estimate	High Estimate	Mean Estimate	
A	1.00	1.86	3.08	1.97	0.18	0.47	0.96	0.49	8
Backreef	0.63	1.17	1.94	1.24	0.11	0.29	0.60	0.31	12
B	1.18	2.18	3.61	2.31	0.21	0.55	1.12	0.58	8
C	0.81	1.49	2.47	1.58	0.15	0.37	0.77	0.40	6
D	3.44	6.37	10.6	6.75	0.62	1.59	3.29	1.69	8
E	11.5	21.3	35.4	22.6	2.07	5.33	11.0	5.65	4
F	16.7	30.9	51.2	32.7	3.01	7.73	15.9	8.18	4
G	3.86	8.93	16.8	9.79	0.70	2.23	5.21	2.45	6
Probabilistic Total	45.6	72.8	117	77.7	8.95	17.7	35.7	20.6	

Notes

1 *Volumes reported are gross (100%) interest for the L6 and EP129 R2/R3 permit areas.*

2 *Totals are the probabilistic aggregation of individual reservoir units.*

3 *"GPoS") means the Geological Probability of Success.*

Table 1: Undiscovered Oil Initially-in-Place and Prospective Resources Summary for the L6 and EP129 R2/R3 Permit Areas (100% Basis)

Recommendations

RPS recommends the following subsurface activities be considered to further reduce uncertainties in the asset:

- Test Backreef-1 to confirm the fluid content of the reservoir;
- Review well formation tops for consistency;

- Reprocess and include additional 2D seismic that was recorded within the permit areas if it becomes available;
- Consider the feasibility of using VSP to evaluate the structure near wellbore; and
- Shoot modern 2D seismic to determine the stratigraphic and/or structural nature of the Backreef Lead and better define the closures of all Leads.

Standard applied

Prospective Resources have been determined in accordance with the SPE/WPC/AAPG/SPEE Petroleum Resources Management System (2007). RPS has used standard petroleum engineering, geological and geophysical techniques in these evaluations. We have estimated the degree of uncertainty inherent in the measurement and interpretation of the basic data.

Reliance on source data

The content of the report and our estimates of potential resources contained therein are based on seismic, exploration well data, and other geological data provided to us by OBL. The company provided us with all relevant and available data at the time of the drafting of this report. We have accepted, without independent verification, the accuracy and completeness of this data.

Qualifications

RPS is an independent consultancy providing a comprehensive range of technical services and economical analysis to the petroleum industry. Except for the provision of professional services on a fee basis, RPS does not have a commercial arrangement with any other person or company involved in the interests that are the subject of this report. Mr David Guise (Managing Director – Consulting, Australia Asia Pacific) has supervised the evaluation.

David Guise has been registered as a Professional Engineer with the Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA) since 1980. APEGGA has regulated the practice of engineering, geology and geophysics in Alberta, Canada since 1920 and the Association's authority is derived from provincial statute. He is also a member of the Society of Petroleum Engineers Twenty-five Year Club. He has over 30 years of domestic and international petroleum engineering and operating experience in both onshore and offshore environments. David has substantial experience and knowledge of field development planning, production optimisation and reserve estimation and holds a Diploma of Technology, Petroleum Technology (1973), from the Southern Alberta Institute of Technology and a B.Sc. in Petroleum Engineering from the University of Wyoming (1979).

Basis of Opinion

The evaluation presented in this report reflects our informed judgement based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests.

Basis of Opinion

The evaluation presented in this report reflects our informed judgement based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests.

It should be understood that any evaluation, particularly one involving exploration and future petroleum developments may be subject to significant variations over short periods of time as new information becomes available. All interpretations and conclusions presented herein are opinions based on inferences from geological, geophysical, engineering or other data. The report represents RPS's best professional judgement and should not be considered a guarantee of results. Our liability is limited solely to OBL.

Consent

The report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. The report must, therefore, be read in its entirety.

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Yours faithfully,

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APPENDIX - GLOSSARY OF TECHNICAL TERMS

1C	Low Estimate Contingent Resources
2C	Best Estimate Contingent Resources
3C	High Estimate Contingent Resources
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserve
Acre	Area in acre
AOF	Absolute Open Flow
API	American Petroleum Institute
B	billion
bbl	barrels
bbl/d	barrels per day
BBTUD	Billions of British Thermal Units per Day
bcpd	barrels of condensate per day
BOE	barrel of oil equivalent
B_g	gas formation volume factor
B_{gi}	gas formation volume factor (initial)
B_o	oil formation volume factor
B_{oi}	oil formation volume factor (initial)
B_w	water volume factor
bcpd	barrels of condensate per day
bopd	barrels of oil per day
brt	below rotary table (depth reference)
Bscf	billions of standard cubic feet
BTU	British Thermal Unit
bwpd	barrels of water per day
°C	Temperature in Centigrade
cc	cubic centimeter
CGR	condensate gas ratio
cP	Viscosity in centiPoise
DCQ	daily contracted quantity direct
DST	Drill Stem Test
Entitlement Volumes	the volumes of oil and/or gas which a Contractor receives under the terms of a PSC
ELT	Economics Limit Test
EUR	Estimated Ultimate Recovery

APPENDIX - GLOSSARY OF TECHNICAL TERMS	
°F	Temperature in Fahrenheit
FBHP	flowing bottom hole pressure
FTHP	flowing tubing head pressure
FTHT	flowing tubing head temperature
ft	Length in feet
ft^3	Volume in cubic feet
ftSS	depth in feet below sea level
GEF	Gas Expansion Factor
GIP	Gas in Place
GIIP	Gas Initially in Place
gm	Weight in grams
gm/cc	Density in grams per cubic centimeter
GOR	gas/oil ratio
GPoS	Geological Probability of Success
GRV	gross rock volume
GSA	Gas Sales Agreement
GWC	gas water contact
Ib	Weight in pounds
Ib/cuft	Density in pounds per cubic feet
KB	Kelly Bushing
km	Length in kilometres
km^2	Area in square kilometres
km^3	Volume in cubic kilometres
m	Length in meter
MM	million
MM$	million US dollars
MD	measured depth
mD	permeability in millidarcies
MDT	Modular Formation Dynamics Tester
m^3	cubic metres
m^3/d	cubic metres per day
MMscf/d	millions of standard cubic feet per day
Money of the Day	Cash values calculated to include the effect of inflation
NTG	net to gross ratio
NPV	Net Present Value

APPENDIX - GLOSSARY OF TECHNICAL TERMS

OWC	oil water contact
P1	Proved Reserves
P2	Probable Reserves
P3	Possible Reserves
P_{10}	Probability of 10% chance the value would be larger than the reported and considered high value
P_{50}	Probability of 50% chance the value would be larger than the reported and considered best value
P_{90}	Probability of 90% chance the value would be larger than the reported and considered low value
P_b	bubble point pressure
P_c	capillary pressure
petroleum	deposits of oil and/or gas
phi	porosity fraction
phie	Effective porosity fraction
p_i	initial reservoir pressure
PRMS	Petroleum Resources Management System (SPE Terminology)
PSC	Production Sharing Contract
PSDM	Pre-stack Depth Migration
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
rcf	Volume in reservoir cubic feet
Real	Cash values calculated to exclude the effects of inflation
SEG	Society of Exploration Geophysicists
scf	standard cubic feet measured at 14.7 pounds per square inch and 60°F
scfd	standard cubic feet per day
scf/stb	standard cubic feet per stock tank barrel
stb	stock tank barrels measured at 14.7 pounds per square inch and 60°F
stb/d	stock tank barrels per day
stb/MMscf	stock tank barrels per million standard cubic feet measured at 14.7 pounds per square inch and 60°F
STOIIP	stock tank oil initially in place
S_w	water saturation
US$	United States Dollars
TAC	Technical Assistance Contract

APPENDIX - GLOSSARY OF TECHNICAL TERMS

TAN	Total Acid Number (of oil)
Tscf	trillion standard cubic feet
TVDSS	true vertical depth (sub-sea)
TVT	true vertical thickness
TWT	two-way time
US$	United States Dollar
V_{sh}	shale volume
WI	Working Interest
WC	water cut
WHP	Well Head Pressure
ϕ	porosity

RESERVES AND RESOURCES DEFINITIONS AND GUIDELINES

Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association

of Petroleum Geologists (AAPG), and Society of Petroleum Evaluation Engineers (SPEE)

Petroleum Resources Management System (PRMS)

Definitions and Guidelines ([1])

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

[1] These Definitions and Guidelines are extracted from the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document ("SPE PRMS"), approved in March 2007, and available, free and in full, at: www.spe.org/spe-app/spe/industry/reserves/index.htm

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.

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.

Proved Reserves

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

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes:

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

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

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.

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.

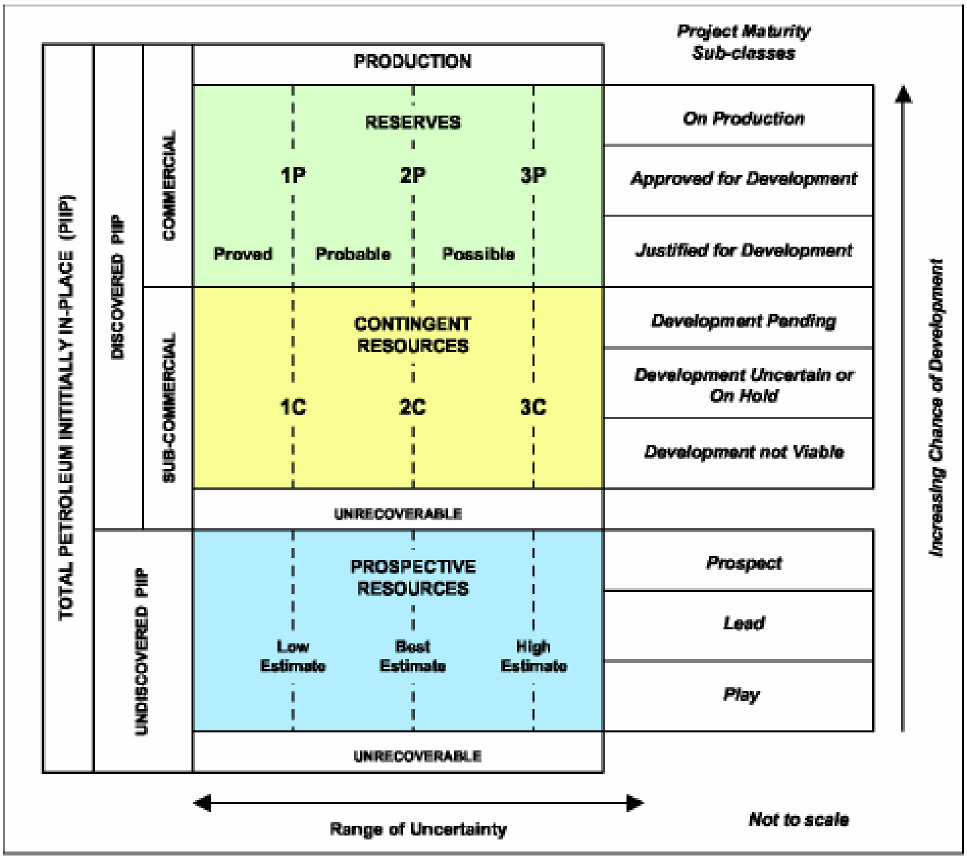
Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

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.



Project Maturity
Sub-classes
PRODUCTION
RESERVES
1P
2P
3P
Proved
Probable
Possible
CONTINGENT
RESOURCES
1C
2C
3C
UNRECOVERABLE
PROSPECTIVE
RESOURCES
Low
Estimate
Best
Estimate
High
Estimate
UNRECOVERABLE
TOTAL PETROLEUM INITITIALLY IN-PLACE (PIIP)
DISCOVERED PIIP
UNDISCOVERED PIIP
COMMERCIAL
SUB-COMMERCIAL
On Production
Approved for Development
Justified for Development
Development Pending
Development Uncertain or
On Hold
Development not Viable
Prospect
Lead
Play
Increasing Chance of Development
Range of Uncertainty
Not to scale