

OIL BASINS LIMITED (OBL)

Inexpensive Call Option

DIRECTORS

Kim W McGrath, Executive Chairman
 Neil F Doyle, Director and CEO
 Nigel Harvey, Non-Executive Director

MARKET DATA

ASX Code:	OBL
Current Price	\$0.021
52 week Share Price Range:	\$0.02 - \$0.04
Market Capitalisation:	\$7.3 million

CAPITAL STRUCTURE

Shares on Issue:	345.3 million
Unlisted Options; @1.5c; 30/6/12	64.9 million
Unlisted Options; @4c; 30/6/14	69.0 million



MAJOR SHAREHOLDERS

LNG Limited	6.6%
Management	5.0%

SENIOR ANALYST

Simon Oaten
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KEY POINTS

Oil Basins Limited (OBL) is an oil & gas exploration and development company with three focus areas (Carnarvon, Gippsland and Canning Basins). Its assets are located both onshore and offshore.

OBL is unusual in the junior E&P sector in that it has 2C assets (proven & probable contingent resources) of large potential value, relative to its market capitalisation.

OBL's exploration portfolio covers conventional oil and gas (Gippsland), conventional, coal seam gas (CSG) and unconventional shale gas (USG) in the Canning Basin. Recent deals by large multinationals in the Canning Basin (Mitsubishi with Buru, Conoco Phillips with New Standard) and also in the Gippsland (Beach/Amour Energy) highlight this potential value.

USG is now a major, and growing, part of world oil and gas production, and Australia is blessed with very large in-place resources. The Canning Basin is known to have very high quality source rocks, and has very good potential. OBL has two permits that have significant USG / CSG potential.

Given success or farm-outs at any of its projects could be worth multiples of the current share price. OBL is clearly leveraged to news flow in terms of any asset deals, and also the flow-testing of its potential discovery at the Backreef-1 well, which is expected to occur during the second quarter 2012.

We estimate a "fair and reasonable" value for the company's assets of around 5cps "risked", with a high-side case of 9cps "risked".

INVESTMENT PROPOSITION

Junior oil companies are inherently volatile, with share prices driven by exploration events and news flow surrounding this, but given more sanguine capital markets, OBL can provide additional high-leverage, and 'price discovery' to investors via:

- Sale of assets;
- Farm-out of prospective oil resource plays;
- Farm-out of prospective CSG / shale gas plays;
- Farm-down of its Gippsland prospects.

OBL can also add value to its assets via its strategic relationships with DU-EL Drilling Services Pty Ltd (a well-credentialed drilling and engineering services company) via demonstration of increased recovery factors at Cyrano, and lowering the capital costs via innovative development solutions.

OBL has an option agreement with LNG Limited (independent LNG project developer) which could increase the value of future gas discoveries by enabling access to international gas. This approach was used by many of the CSG companies in eastern Australia to maximise value for their shareholders. News flow over the coming 12-months should provide catalysts for value triggers:

- A flow-test at the Backreef-1 well (potential discovery or defined location) in early 2012, which could open up a significant new play type, with substantial volumes mapped leads;
- Initial appraisal of the CSG and USG gas potential within the Canning Basin, which could be very large, and it may eventually provide back-up/ ramp-up raw gas supply for nearby LNG exports (from James Price Point);
- The small Cyrano Oil Field could be commercially viable, if development costs can be reduced to around \$65m or below, and/or gross recoverable volumes exceed circa 3 MM bbls.

Given that any farm-out deals would likely add substantial value for shareholders, and this does not appear to be reflected in the current share price, OBL is clearly leveraged to news flow in 2012.

EXECUTIVE SUMMARY

OBL is an E&P exploration and development company. Since its re quotation on the ASX on 23 August 2006, the company has expanded its portfolio, with modest capital outlays, from a farm-in focussed on the Gippsland Basin. The company now has assets in three proven Basins:

- Offshore Gippsland Basin (Vic P/41: 12.5% rights - 5% direct, 7.5% indirect; Vic P/66 17% direct interest);
- Onshore Canning Basin (WA: Backreef Area 100% beneficial rights; 50% interest in 5/07-8EP);
- Offshore Carnarvon Basin (WA: RL R3/R1 – 100% of Cyrano Oil Field).

OBL aims to maximise shareholder value via the identification of highly leveraged exploration farm-in opportunities, acquisition of appraisal (pre-development) opportunities, the acquisition of mature production opportunities, and if appropriate, strategic corporate investments.

OBL has developed strategic relationships with "operator to operator" DU-EL Ltd and LNG Limited (an Independent LNG plant developer). OBL is already an approved Operator in W.A. (both onshore and off-shore),

and as such has the technical expertise to carry out all aspects of hydrocarbon exploration, appraisal and development (well design drilling, completions, and production operations).

Its portfolio includes: a discovered oil resource, a potential onshore oil field, 14+ drill-ready prospects in both the Gippsland and Canning Basins, most of which are covered with 3D seismic, with supporting “AVO” signatures. The keys to unlocking shareholder value are:

- Demonstration of flow rates from the Backreef Area oil discovery, which, in the event of success, would greatly enhance the prospectivity of the 117 MM bbls mapped prospective potential within 8 separate leads within the Backreef Area;
- Farm-down of interest in Vic/P41;
- Demonstrate potential for both CSG and shale gas within Permit 5/07-8 EP onshore Canning Basin, with future processing infrastructure some 170km away;
- Develop a low-cost engineering solution to the undeveloped Cyrano Oil Field.

Success in any of these projects would add substantial value, while a farm-out of its present 50% CSG / USG interests onshore Canning Basin could be worth net \$20-\$40m in value compared to recent deals.

The following table outlines our assessment of the “risky” underlying asset value ranges for OBL’s asset base:

OBL - Indicative Valuation

	Low Case	High Case	Risky Low	Risky High	
	Upside		EMV	EMV	
Cash @ 30 Sept	1.5	1.5	1.5	1.5	Sept 2011
Other Assets	0.0	0.0	0.0	1.0	
less Drilling obligations	-1.5	-1.5	-1.5	-1.5	Estimate
less Seismic obligations	0.0		0.0	-2.0	2013 for Vic P/66
Vic P41 - 12.5	31.0	45.0	7.8	11.3	25% of EMV
Vic/P66	1.0	5.0	1.0	1.0	Estimate
Cyrano	7.5	26.0	2.4	7.8	30% of EMV
Backreef Area	3.5	10.0	1.8	5.0	50% EMV
CSM / Shale	22.4	27.4	4.5	5.5	20% of EMV
Total	65.4	113.4	17.4	29.5	
TSO	345.3	\$0.19	\$0.33	\$0.05	\$ps
Options	133.9	1.5 and 4.0 exercise price			

Source: Gordon Capital estimates

Hence we estimate a “fair and reasonable” value for the company’s assets of around 5cps “risky”, with a high-side case of 9cps “risky”. Any success with the flow-test of the Backreef accumulation, would be positive from both a potential cashflow perspective, and also upgrade the potential of the seven other mapped leads within the permit. Note this does not include any value for:

- Strategic value of the LNG Limited Alliance (essentially a call option over plant at cost upon future exploration success, and achieves export price parity for future gas discoveries);
- Additional upside from mapped potential within the Backreef Area (mean 117MM bbls potential);
- Future expected medium term increases in east coast gas prices and its impact on valuation of offshore gas exploration assets.

The success upside case is around 20-33 cps, with a farm-out of the CSG/shale-gas plays and a farm-out of Vic P/41 required. This number has upside if OBL can increase the recoverable resource size for the Cyrano field, by using the latest modern down-hole ESPCP technology, and multi-lateral completions.

BACKGROUND

Oil Basins is involved in exploration for oil and gas in the offshore Gippsland Basin waters of south-eastern Australia, the onshore Canning Basin of Western Australia and the offshore Carnarvon Basin waters of Western Australia. All assets are situated in good hydrocarbon addresses and all are strategically close or adjacent to existing or future development infrastructure.

Since being quoted on the Australian Stock Exchange in August 2006, the company has significantly expanded its initial portfolio of two permits at very modest cost and now has formal title or Rights to earn interests in a portfolio of attractive drill-ready exploration assets. This portfolio presently includes three (3) offshore and two (2) onshore petroleum exploration permits in Australia – covering onshore and offshore oil exploration & development, CSG and USG, as follows:

- 12.5% Rights (direct and indirect) to Vic/P41 situated in offshore Gippsland Basin;
- 17% interest in Vic/P66 situated in offshore Gippsland Basin;
- 100% Beneficial Rights & operator to Backreef Area, onshore Canning Basin;
- 50% interest in 5/07-8 EP situated onshore Canning Basin (conventional petroleum, designated operator CSG and USG prospectivity);
- 100% interest & operator of R3/R1 situated in offshore Carnarvon Basin hosting the small undeveloped Cyrano Oil Field – significant 250% upward revision of OIP resources was announced on 1 April 2011.

On 4 August 2010 the Company and Liquefied Natural Gas Limited (ASX code LNG) signed a non-exclusive Strategic Alliance Agreement (SAA) in respect of natural gas, coal seam gas and shale gas in the Canning Basin, Western Australia for the purpose of evaluation and the appropriate development of projects and in particular an LNG production facility in the Canning Basin Region using feedstock sourced from OBL permits.

Under the terms of the SAA, OBL will have the right, but not obligation, to invest in any such LNG project up to a maximum of 20% on an at cost basis, however this maximum becomes 30% should OBL and its JV consortia deliver certified 2P gas reserves of at least 1.0 Tcf (in accordance with SPE definitions) within 4 years of work programs commencing in the field.

This potentially will attract farm-in interest in the untapped CSG and USG potential of its attractive and strategic exploration portfolio in the Fitzroy Trough, Canning Basin.

OBL acquired an initial 20% stake in the Backreef Area in February 2006, specifically targeting a stratigraphic oil play within the previously undrilled Kimberley Downs Embayment. In 2007 OBL pioneered the use of remapping and digitising vintage 2D seismic data with modern PSTM and PSDM techniques. After the ‘out-of court’ Settlement of the Backreef Dispute with Arc Energy NL in October 2008, OBL moved to 80% rights and earned 100% equity rights via drilling the Backreef-1 well. OBL assumed Operatorship in 2010.

The Backreef-1 well encountered a 12m oil column in (and potentially up to net 39m +/- in 20% porosity Yellow Drum dolomites). Should the flow test prove positive, it would considerably enhance the prospectivity of OBL’s other mapped newly mapped leads in the Backreef Area (indeed mapping by OBL using advanced Schlumberger PetrelTM software indicates that there is a potential for a large stratigraphic oil play both to the east and north of Backreef-1).

OBL acquired an initial 15% stake in the Cyrano field, which is held under a “Retention Lease” and increased this to 100% in 2011 (effective purchase price of 60c/bbl). This small field (defined by 3 wells and 3D seismic) was originally going to be part of a staged development (probably via tie-back to Arlie Island with overall capex estimated at US\$130m). OBL remapped the existing 3D seismic and has shown that there is a significantly greater volume of “oil in place” at Cyrano (approx. 250% increase). We estimate capital costs need to be below \$65m for this project to be viable at current oil prices, alternatively, a way of producing “more barrels” from the field needs

to be found, possibly by using down-hole pumps. OBL has a strategic alliance with offshore engineering firm DU-EL, which has estimated gross capex of circa US\$59m for an extended well test (EWT), while OBL has indicated the development could be done using leased equipment (jack-up rig, FSO vessel and working capital) for around \$US30m. Reservoir engineering studies will be required to de-risk the project.

OBL and Liquefied Natural Gas Limited (LNG) have a non-exclusive Strategic Alliance Agreement, such that OBL has the rights to a 20% investment in a future LNG Plant Project (at cost), if OBL and/or any JV partners discover and certify 2P gas reserves of greater than 1.0 Tcf, within 4-years of the award of permit 5/07-8EP. Further, OBL has the option (right, but not the obligation), to invest up to 30% in any such LNG Plant Project on an “at cost basis”. Importantly, LNG Limited announced on 13 December 2011, that its CNPC Alliance Affiliate HQC and major shareholder had completed designs for 1Mtpa to 1.5Mtpa LNG plant into 5 construction modules (could be pre-made offshore, likely in the PRC) and simply shipped and assembled onsite at its Fisherman’s Landing project site, near Gladstone, at an estimated cost of circa US\$1.1 bn.

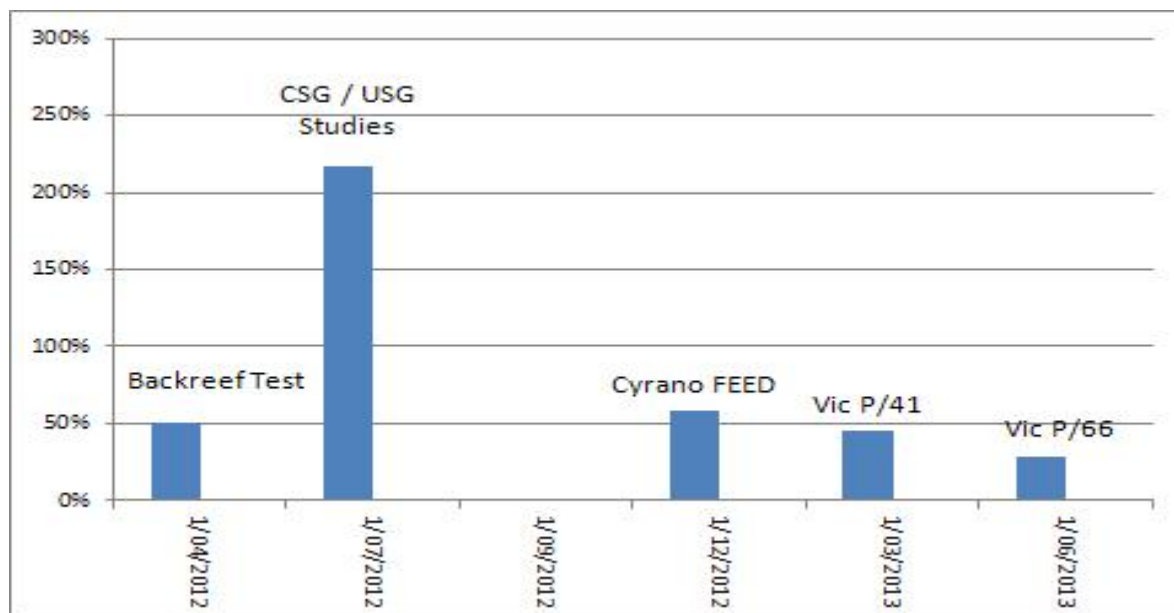
In the event of success in pioneering gas exploration, OBL may then have the ability to leverage its CSG and shale gas potential to a third party, as the strategic alliance essentially offers export US dollar gas prices for any future discoveries from its Canning Basin exploration assets. Depending upon how Permit 5/07-8 EP is farmed out and explored for, the future CSG / USG gas potential may allow OBL to simply offer the whole Permit to one partner or, in a ‘novel unconventional managed approach’, elect to offer future Joint Venture Partner (s) equity in a LNG Project, by dividing EP 5/07-8 EP (62 graticular blocks in total) into a number of JVs seeking CSG/USG delineation. Basically under the terms of the OBL-LNG Alliance every 1 Tcf of 2P feed can potentially supply another future modular LNG Plant – OBL’s interest remains 20% to 30% which can be used to facilitate future JV Partnerships with an “appropriate promote”(without value destroying competition).

STRATEGIC DIRECTIONS

Small-cap oil & gas companies derive value from either exploration success or project development of assets. OBL has a portfolio that has excellent leverage to success, with multiple value triggers:

- Strategic value of LNG Limited Alliance, which is essentially a call option over an LNG plant “at cost” upon future exploration success, and achieves export price parity for future gas discoveries. This could enable OBL to maximise value of any farm-in to its potentially large scale CSG and shale-gas resource plays;
- Strategic relationship with DU-EL which aims to demonstrate increased recoverable volumes and lower capital costs at a small oil field – this approach could then be used at other currently uneconomic accumulations;
- Successful flow testing of the Backreef Area accumulation, which in the event of success would open up and de-risk a mean 117MM bbls potential, adding substantial value. It would also add potential cashflow and underlying Net Present Value (NPV);
- Expected future expected increases in east coast gas prices and its impact on valuation of OBL’s Vic P/41 offshore gas exploration assets.

The chart below provides an indicative timeline for various development initiatives to be undertaken by OBL over the next 18 months mapped against their potential value relative to the current share price:



Source: Gordon Capital estimates

In terms of potential values, we estimate the following for OBL:

The upside case for the Backreef Area is material, as it would significantly re-rate and change the “probability of success” of future wells in the area. This could add circa \$10m+ in risked exploration upside, as a result of changing “POS” from 3% to say 15%. Successful flow test at Backreef-1 (say conservatively 300k bbls recoverable, 50 bopd rate): NPV (10) – \$3.5m (1 cps).

The Backreef-1 well has a 12m oil column (potentially up to 39m +/- within the upper Yellow Drum Dolomites, with good porosity), with the main reservoir at 960m. Should the flow test prove positive, it will enhance the prospectivity (and hence potential value) of the other mapped leads within the permit, due to a higher probability of success (i.e. a higher potential value). Note nearby Blina Oil Field (1981) discovery well produced 963 bopd under test (albeit in the deeper Nullara limestone zone) and the field has produced 1.9 MMbbls from an estimated STOOIP of 5.7MMbbls. There is also substantial USG potential from the deeper section of the Backreef Area (below 1700m).

Simple shallow core holes in 5-07/08 EP would demonstrate coal seam thickness (a 20m gross coal seam was recorded in the Booran-1 well at around 700m depth), and allow gas content measurement, and could upgrade the resource potential substantially. This could potentially be conducted within the “historic driving trail” from the right of way easement of the sealed roads within the Permit. A farm-out could add \$20-40m in potential value (5.6 – 11.2 cps). The USG may also have “wet-gas” potential, depending on depth of burial.

The non-Operated Vic P/41 permit in the Gippsland Basin is still arguably OBL’s best asset in terms of prospectivity, with mean mapped prospective resources of circa 800MM boe, defined by modern 3-D seismic. Recent onshore farm-ins suggest this permit has value upside, and we estimate a reasonable farm-in would add \$80-100m in gross value, net \$10-12.5m (2.8 cps).

For the Cyrano Oil Field, we estimate an Expected Monetary Value (“EMV”) of around \$7.5m, and given this asset requires a FEED study, we have “risked” this value by 30%, hence this could be worth circa \$2.3m - \$26m to OBL (and over \$40m net under certain scenarios). Note this is substantially greater than the \$0.5m purchase price. A farm-in, or future unitisation with Apache would underpin value for OBL.

Should OBL and DU-EL demonstrate increased recoverable volumes and a lower capital cost solution for the Cyrano field, this approach could enable other small fields to be economically developed.

The option deal with LNG Limited (an Independent LNG plant developer) could enable OBL to deal its CSG / USG blocks on a highest and best use basis, and while difficult to value (we view this as a contingent call option), it clearly has strategic value.

VALUATION

We have used a combination of Expected Monetary Value (EMV) and risked NPVs to value OBL's asset base.

We derive a value of \$17.5m risked (\$0.05/share) to \$29m risked (\$0.09/share) in the high-side case. Several low-cost opportunities are available to OBL to drive value, namely a flow-test of the Backreef-1 accumulation (circa \$850k to test) and a second well East Blina-1 (Lead "A"), by 31 October 2012 (circa \$1.5-2.5m). If OBL is successful in farming these wells out the net cost to OBL is likely to be neutral.

With respect to Permit 5/07-8EP no activity can commence in 2012 until Native Title is resolved (Mediation is finalised or a Determination is made). Subject to this, the unconventional work program will include core holes to test the gas content and seam thickness in 5/07-8 EP (circa \$800k+ to test and laboratory work). The conventional oil targets will focus on re-mapping of Yeeda-1, and shooting 2D seismic, likely to be farmed out. We have not included options in the above.

Oil Basins Limited														
Prospect or Lead	Permit	Operator	Net Interest	Gas/Oil	% Interest Within Permit	Drill Ready defined by 3D	Mean Gross Reserves M/Mbbls	Mean Gross Reserves Bcf	Mean Net Reserves M/Mbbls	Mean Net Reserves Bcf	Farm-in Value A\$/M	Implied Value by BPT / LKO AS/bcf or US\$/bbl	Risk Assessment POS	Comments
Kipling Lead	Vic/P41	OBL	13%		90%	3D	124	620	14	70	n/a	11.9	25%	3D, AVO support
Fenchley Gnat Reach lead			0.175	Gas	90%	3D	145	1366	16	154	n/a	26.1	20%	
Fenchley Halibut sst				Gas	100%	3D	39	75	5	9	n/a	1.6	10%	
Cotton				Gas	100%	3D	60	1	3	0	n/a		10%	
Scorpion				Gas	100%	3D	13	1	2	0	n/a		10%	
Oscar				oil	100%	3D	19	12	2	2	n/a		10%	
Oscar				oil	100%	3D	19	13	2	2	n/a		10%	
Lead A				gas	?	2D		?					5%	requires 3D
Lead A extension	Vic/P66		17%	gas		No				49	237		5%	Seismic reqd
Eackreef Area	WA	OBL	100%	oil	100%	2D	1		1			0.00	5%	354 sq km's, 12m column
Lead E				oil	100%		5		5				5%	
Lead F				oil	100%		7		7			0.00	5%	
Lead G				oil	100%		2		2				5%	
Lead A				oil	100%		1		1				10%	risk reduces if Backreef-1 flows
Lead D				oil	100%		3		3				5%	
Cyrano	WA RL3	OBL	100%	Oil	100%	3D	1.5		1.5			0	100%	discovered, volumes are key
							0		0					
CSM potential	WA	OBL		Gas	100%	N		600	0	250		0	5%	core holes reqd
Shale Potential			50%	Gas	100%	N	20	600	10	250			5%	core holes reqd
														0

Source: Gordon Capital estimates, NB Lead "A" in the Gippsland is partially defined by 2D, shot in 2008

Market Relatives

The table below outlines the booked reserves by company, and the uses market capitalisation, cash/debt to derive an implied market valuation for the Enterprise Value of each company's oil and gas assets.

Gippsland Basin Comparables

Gippsland Basin	Code	Price	TSO M	Mar Cap \$M	Debt est \$m	Cash est \$m	Excess Assets	EV - A\$	Comments
Nexus Energy	NXS	\$ 0.215	1326.0	\$285.1	\$299	62.0		522.1	Longtom production, Crux development
Bass Strait Oil Co	BAS	\$ 0.018	388.0	\$7.0	\$0	2.0		5.0	Vic exploration
Oil Basins	OBL	\$ 0.020	345.3	\$6.9		1.5		5.4	Vic exploration, Canning exploration
Moby Oil&Gas	MOG	\$ 0.023	322.0	\$7.4	\$0	3.5		3.9	Vic, Carnarvon, Browse exploration

Canning / Carnarvon Basin Comparisons

Canning Basin	Code	Price	TSO M	Mar Cap \$M	Debt est \$m	Cash est \$m	Excess Assets	EV - A\$	Comments
Oil Basins Limited	OBL	\$ 0.02	345.3	\$6.9	0	1.5		5.4	Canning / Gippsland
Buru Energy	BRU	\$ 1.25	234	\$292.5	22	35.5		279.0	Canning
New Standard Energy	NSE	\$ 0.35	282	\$98.7	0	27.8	18.0	52.9	Canning / USA

Source: ASX data

Hence, OBL is highly leveraged to any farm-out of its shale-gas plays.

FINANCING AND RISKS

OBL has the current capital structure:

Current Market Capital	
FPO (m)	345.3
Options	
1.5c 30 June 2012 (m)	64.9
4.0c 30 June 2014 (m)	69.0

Source: ASX data

The table below is our estimated financing requirements for OBL over the next 12-18 months:

Project	Cost \$m
Backreef Test	0.8
Blina East-1 well	2.5
CSM / USG studies	2.0
Cyrano FEED study	3.5
Vic P/66 & Vic P/41 seismic	0.5

Source: OBL announcements, Gordon Capital estimates

Funding for OBL is likely to come from a combination of farm-outs and additional equity capital.

What this highlights is for relatively small capital outlays, OBL has very high leverage in the event of success from a positive flow test for Backreef Area, and any asset farm-outs.

We view the principal risks for OBL as follows:

- Access to capital;
- Low permeability at the Backreef-1 well (could be countered by fracture stimulation of the well bore/ and or modern low radius horizontals);
- No gas charge observed in the shallow Permian coals in 5/08-8EP;
- Depth of burial of shale formations in 5/07-8 EP;
- Poor results from the reservoir simulation studies for the Cyrano asset;
- Offshore well costs and its impact on Vic P/41 valuation;
- No drillable structures after seismic in Vic P/66.

THE PROJECTS

Gippsland Basin Vic P/41 (OBL 5%, earning additional 7.5%)

OBL initially focussed on the Gippsland Basin, via two separate pre-IPO drilling option deals with Moby Oil & Gas Limited (MOG) and Strategic Energy Resources Limited (SER, formerly Eagle Bay Resources), with options to acquire 5% and 7.5% respectively in Vic P/41, prior to the 3D seismic being processed.

While the permit has high prospectively, it would be reasonable to say that the joint venture has not progressed this asset to actual drilling status, due to a lack of funding, high offshore drilling costs, and the chequered history of recent offshore oil and gas developments in Victoria. More positively, the 3-D seismic data and calibration from offset wells (including AVOs) reduce risks, while the potential for higher east-coast gas prices (once the Queensland LNG export projects commence operations in 2015) should result in greater industry interest in these prospects.

The recently renewed Vic/P41 permit (OBL 5% JV interest, 7.5% indirect) covers an area of 540 sq kms, has 3-D seismic coverage over most of the permit, and has six prospects, with water depths of 120m, and mean mapped potential of 2.1Tcf of gas and 440 MM bbls oil/condensate. These are large structures – the Kipling and Benchley prospects cover circa 180 sqkm. Given the AVO seismic responses over the large gas prospects are very similar to the on-trend Kipper gas field (660 bcf, 20 MM bbls condensate), this permit has high prospectivity. The following table outlines the mapped prospect volumes, and assessed geological risks for the two main play types (Golden Beach, Intra-Latrobe sands).

3D Defined Drill-Ready Prospect Defined by AVO	Comments / Target Reservoir	POS (AVO defined)		Gross Stochastic Undiscovered Petroleum (In-Place) Mean Static Volume		Stochastic Prospective Resources (Recoverable)					
						P90		P50		P10	
						OIL MMbbls	GAS Bcf	OIL MMbbls	GAS Bcf	OIL MMbbls	GAS Bcf
Kipling	<i>Within Vic/P41 only</i>	Gas	22%	338	940	00	388	124	020	205	944
		Oil	15%								
Benchley	<i>Golden Beach sst</i>	Gas	17%	397	2,046	76	063	145	1,366	245	1,992
		Oil	13%								
Benchley	<i>Halibut Sub group sst</i>	Gas	24%	88	111	13	58	39	75	74	95
		Oil	16%								
Cotton	<i>Golden Beach sst</i>	Oil / Gas	4%	160	2	33	-	60	1	07	4
Cotton	<i>Halibut Sub-group sst</i>	Oil	16%	31	-	0	-	13	-	19	-
Oscar West	<i>Intra Latrobe sst</i>	Oil / Gas	25%	72	21	-	-	19	12	41	30
Oscar East	<i>Intra-Latrobe sst</i>	Oil / Gas	19%	75	32	-	-	19	18	42	45
		Totals		1,161	3,158	202	1,309	419	2,092	713	3,110

Source: BAS, OBL Ltd

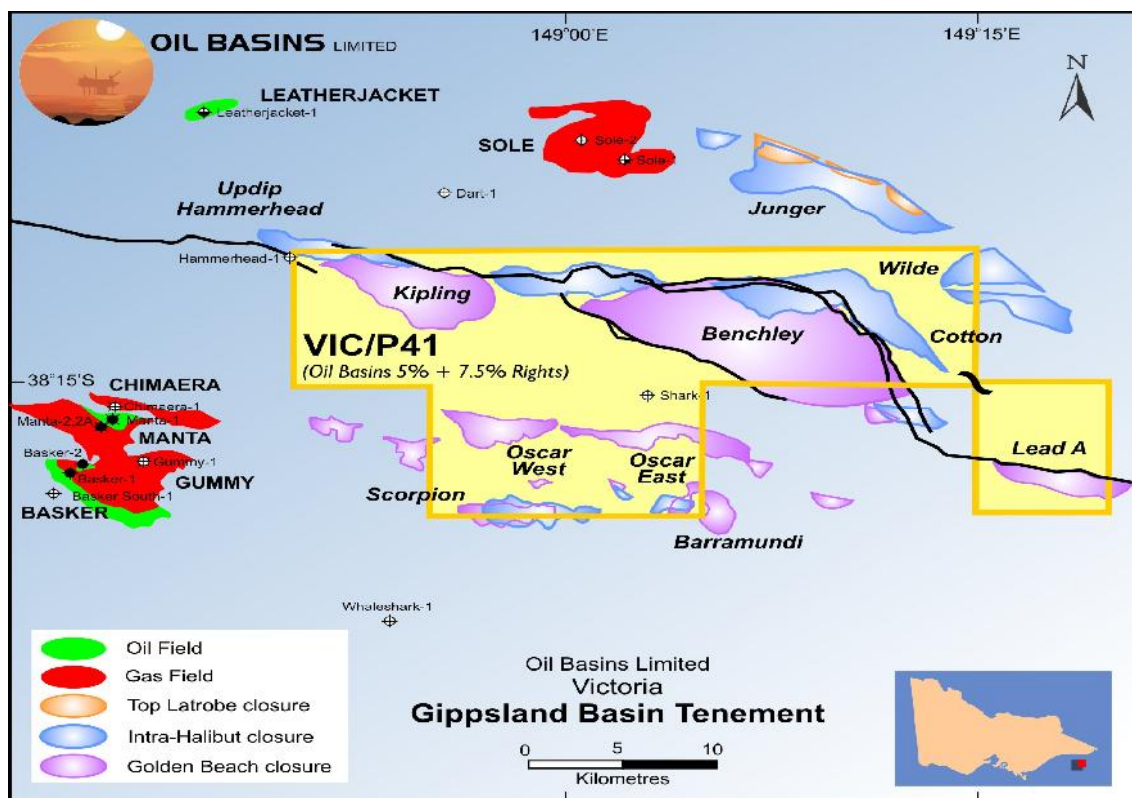
Recent drilling (Esso & BHP) has shown that the down-thrown side of the Rosedale fault is an effective trap, with an oil and gas discovery in Golden Beach sands at South East Remora-1. Recent farm-in deals imply around \$67m for “access to 50%” of 800 PJs of contingent resources (BPT farm-in to LKO, and Amour Energy deal with LKO) implying 17c GJ “in ground value”. We believe this is most likely due to industry expectations that domestic gas prices will increase, as the coal seam methane export industry starts to remove excess capacity from the east coast of Australia around 2015-2017. Additionally, the introduction of the Climate Change Emissions Reduction policy in 2012 should see increased demand from natural gas, as a cleaner burning fuel for power generation. The mean mapped potential within Vic P/41 is circa 5000PJs (undiscovered, so it must be “risked”).

This implies the permit could be valued at around \$50-75m range. Given the permit is likely to contain “wet gas” (LPGs and condensates) it is likely to be strategic from a future domestic gas supply perspective. Further evidence of higher forward gas prices are seen in ExxonMobil indicating it could supply ramp-gas to the Queensland LNG export projects via interstate gas swaps.

Previously, OBL was required to make payments (2006 farm-in agreements) prior to drilling of an exploration well of \$1.65m to MOG and \$2.44m to SER to earn its full legal and beneficial participation rights in Vic/P41, however, this was renegotiated to Nil in respect of MOG’s stake. This means that OBL still has a call option over the future

value of any farm-in agreement. Hence OBL's 12.5% rights could be conservatively valued at up to \$6.2m. Note that OBL has a direct and indirect interest (the latter is not subject to cram down requirements in the event of a third party farm-in).

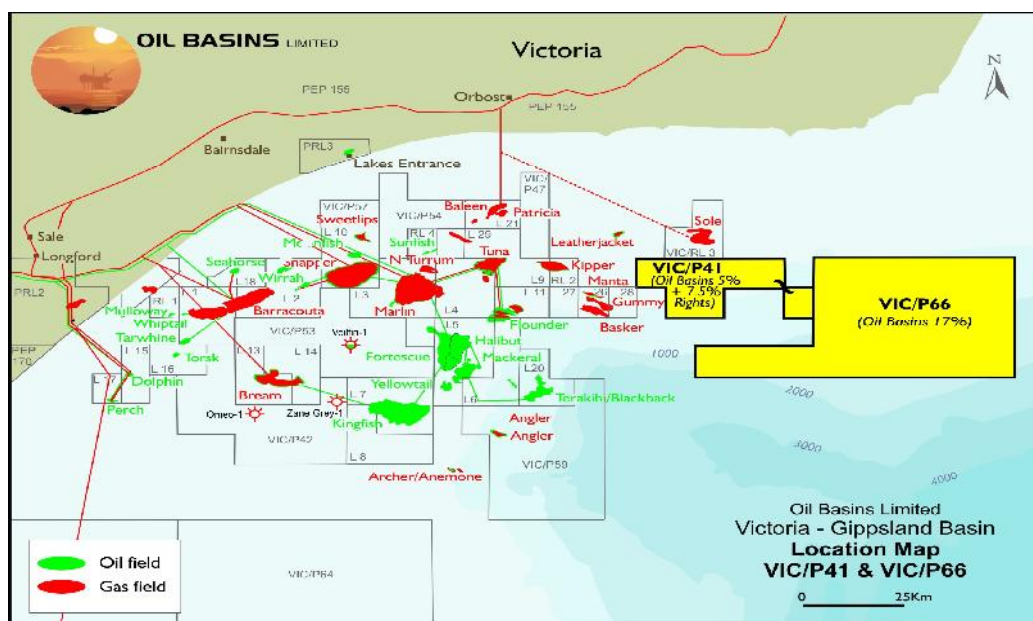
OBL is seeking to consolidate its position in the Gippsland Basin, and regards it as a "core asset". Given the upside P10 mapped potential is in-excess of 3.1 Tcf and 700MM bbls the key to unlocking value is a farm-out, perhaps to a major E&P company.



Source: OBL Limited

Gippsland Basin Vic P/66 (OBL 17%)

This permit is immediately to the west of Vic P/41, and has minimal seismic coverage and no well penetrations. It is likely to contain extensions to the Rosedale fault system, and hence is prospective for similar plays to the adjoining permit. Seismic will probably be acquired in 2013, note "Lead A" above appears to extend into Vic P/66 from limited data. The key to adding value to this asset is funding 3D seismic, demonstration of the plays that exist to the West, and then a farm-out. As such, its value depends on future seismic results, and hence we have used a nominal \$1m valuation.



Source: OBL Limited

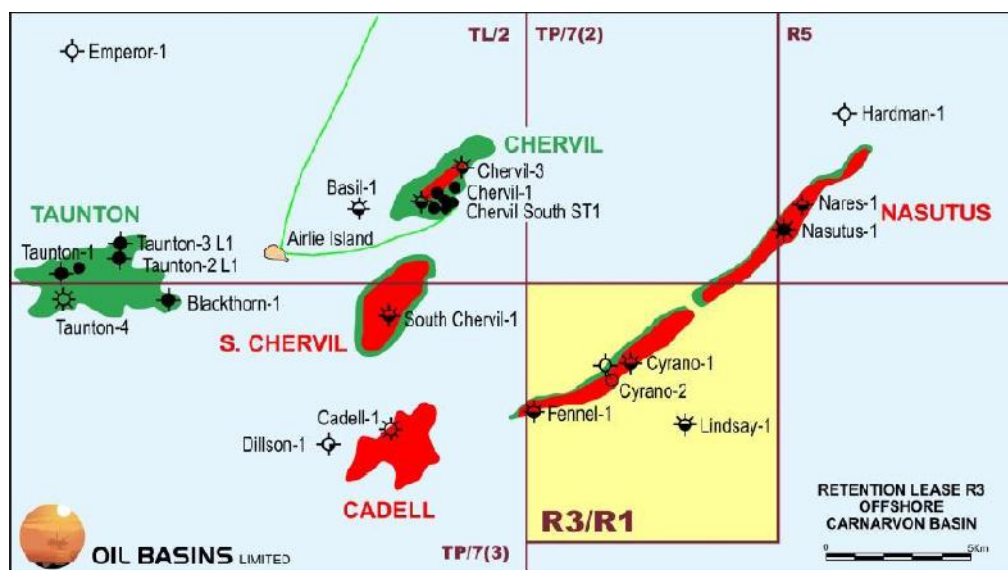
Carnarvon Basin - Offshore (OBL 100%)

During late 2010, OBL acquired 100% of R3/R1 (which contains the discovered Cyrano Oil Field) in the offshore Carnarvon Basin. The final 75% transfer and assignment from the previous operator Tap Oil Ltd was effective 8 April 2011 and required renewal by 6 July 2011. Four wells have encountered oil over 3-separate reservoir sands (Mardie / Airlie / Lower Barrow sands), in 15m water depth. Note the field is the only non-Apache Operated asset between Thevenard Island to the southwest, and Varanus Island to the northeast. The reservoir is shallow (circa 700m deep subsea), low pressure, low permeability reservoir with 23° API heavy oil with a viscosity of 3.95 centipoise (cp) and has a small gas cap. Independent reservoir engineers (RPS Energy) have reviewed the data and have certified:

CYRANO FIELD				
	P10	P50	P90	comment
STOOIP	18.19	10.13	5.28	upgrade in FY11
RPS (15% recovery factor)	2.73	1.52	0.79	No ESPC Pumps
Indicated (with 30% Recovery fact	5.5	3.1	1.6	Mid-point of 23-38% Recovery Factor

ASX release April 2011, Gordon Capital estimates

OBL thus has proven & probable (2C) contingent resources of 1.52 MM bbls and 2.7MMbbls of 3C resources. These figures do not include any estimate of a possible extension of the Nasutus Field (Apache 50%, OMV 50%) into R3/R1.



Source: OBL

OBL lodged its renewal application in June 2011, and was awarded as Operator 100% of retention lease RL R3/R1 on 12 October 2011, for a period of 5 years. The work program is 'modest', circa \$200,000 p.a. (engineering and geological & geophysical studies). OBL then engaged specialist petroleum engineering consultant, DU-EL to examine development options, and on 26 October 2011 OBL announced to the ASX the following:

"DU-EL recommended best option is a standalone low-cost development, in the form of an Extended Well Test (EWT) either as a Hub, or series of EWTs using functional removable and re-deployable equipment."

The most cost effective development would be using a Jack Up Rig (or barge with a modular rig) to drill and production test the well, which would have approximate 1000m horizontal section, by using extended reach drilling (ERD) of the wells. In the basic development concept, separated oil would be temporarily stored in a second 'un-manned' Jack-Up Storage Barge (typically deployed in Asia) prior to offtaking (circa every 10 days) into a conventional leased FSO and regularly offloading crude consignments into a VLCC's in deeper water.

DU-EL recommended the well(s) be completed with modern Electric Submersible Progressing Cavity Pumps (ESPCP), to aid production rates in a low pressure reservoir. By utilising the ESPCP's (which can handle oil/water/gas mixtures), recovery factors (RFs) are assumed at circa 20% to 40% of the STOOIP, which is broadly in-line with studies by the former operator. The wells would then be tested over a period of time to gain further information about the field.

Production estimates for the ERD horizontals using the advanced ESPCP pump units have been made using DU-EL's experience (circa 795,000 bbls/well), with approximate costs estimated up to a two year EWT life following the drilling phase.

OBL has indicated that its assessment of the project is encouraging for the conservative production assumptions. Assuming the following:

- FEED study – estimated circa US\$3.5m;
- Additional working capital of circa US\$5m;
- Initial capital expenditure estimated at circa US\$59m (& less than US\$30m in the leased case);
- Minimum 795,000 bbls recovery per ERD well;
- Initial flow rates 3500 bopd per ERD well;

- US\$80 per barrel oil price (\$100/bbl Tapis less heavy crude differential).

CYRANO Oil Field				
capex \$m	43	50	58	65
PV(10) - \$m	46	38	32	26

Source: Gordon Capital estimates

In 2012, DU-EL and OBL plan to undertake a reservoir simulation study, using inputs from the DU-EL scoping study to assess project risks. If it can be demonstrated that utilising modern down-hole ESPCP with heavy oil in a tight reservoir can lift the recovery factor to circa 30%, it would appear that OBL has an economic project. Also note that the Nasutus Field (Apache 100%) appears to extend into the R3/R1 permit. Logically, unitisation or a joint development / divestment would appear the most obvious solution. Economically, should OBL be successful in de-risking the FEED study, we estimate this asset could be worth in the range \$7-40m, assuming an EWT, or series of EWTs.

Any successful farm-in would immediately put a value on OBL's residual interest in the Permit based initially on the funded work program value.

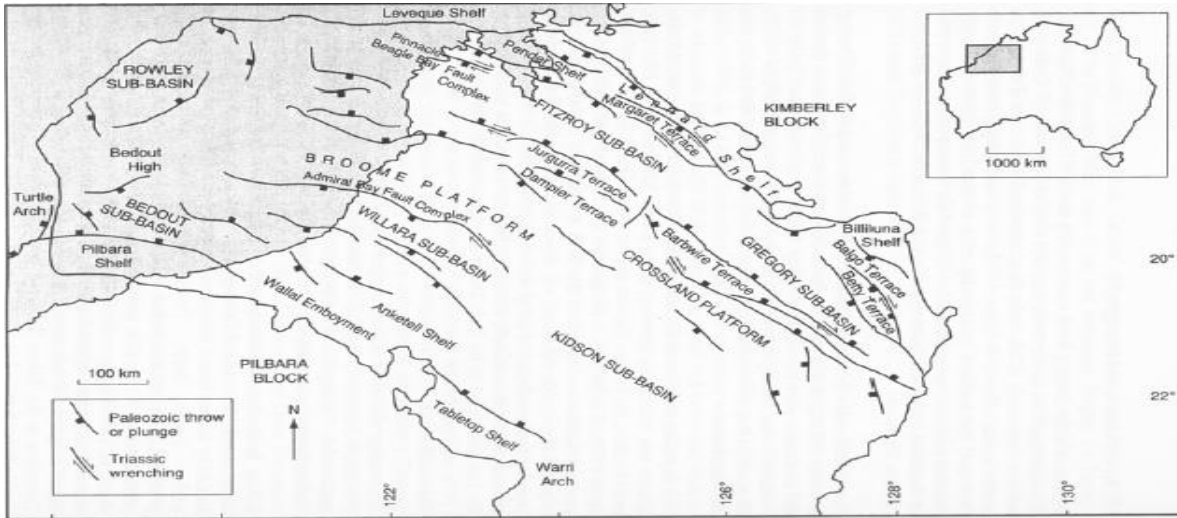
Onshore Canning Basin (OBL 50%-100%)

The large (640,000 sq kms) Canning Basin in north-western W.A. contains 12,000m + of sediments, has several organic-rich shales (including the Laurel, Lower Anderson, and Goldwyer shales) and two main structural elements (faults) separate the main Fitzroy Trough and Willara sub-basin depo-centers.

Some 460 wells have been drilled to date, with only limited success (approximately 15 minor discoveries – with a poor rate of success - circa 3% POS), with average pool sizes less than 2MM bbls, although the recent Buru Energy “Ungani” discovery, on the southern carbonate margin of the Fitzroy Trough is potentially larger. Interestingly, the source rocks have long been considered “world class” in terms of their hydrocarbon generative potential. So either:

- Historical exploration has looked in entirely the wrong place (typically Devonian-aged “reefs”);
- The generated and expelled hydrocarbons have “escaped” to surface; or
- They are still trapped in low permeability shales / limestones and dolomites.

The succession in the onshore basin ranges in age from Ordovician to Cretaceous, but is predominantly Paleozoic. The following diagram shows the main structural elements:

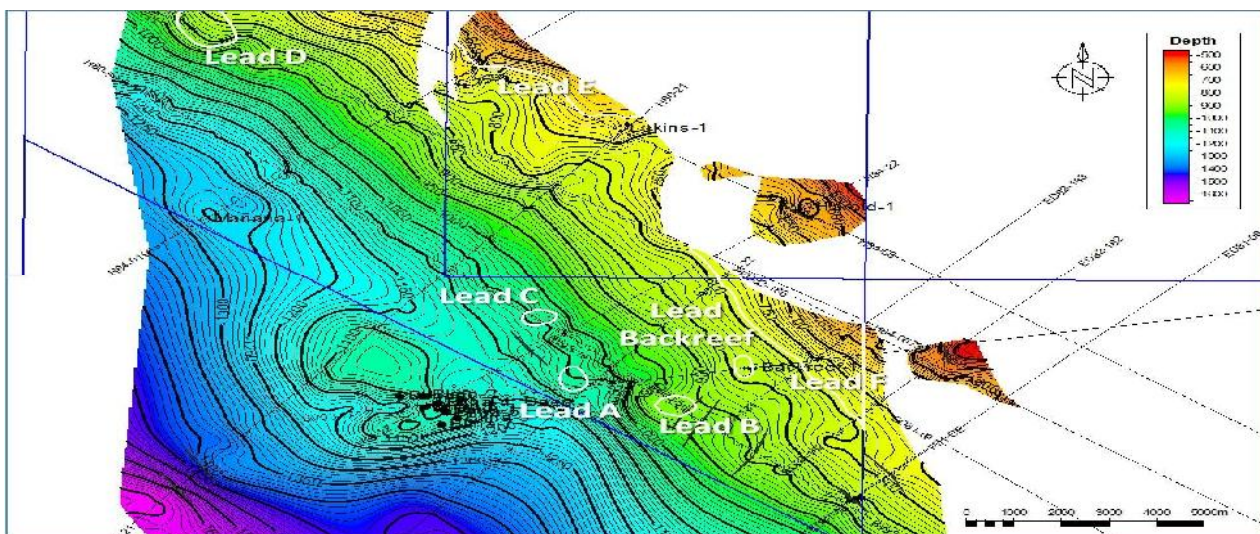


Source: WA Department of Mines and Energy

OBL’s approach is to explore near known oil discoveries within the northern Fitzroy Trough region (a proven hydrocarbon province). It initially acquired a 20% stake in the “Backreef Blocks” in February 2006 via a conditional farm-in from Canadian Golden Dynasty Resources Ltd (“Backreef Play Area”). After the ‘out-of court’ Settlement of the Backreef Dispute with Arc Energy NL in October 2008, OBL moved to 80% rights and then earned 100% equity rights on drilling the Backreef-1 well, assuming Operatorship in 2010.

The Backreef-1 well was drilled to 1800m TD, and encountered oil in the Yellow Drum equivalent Laurel formation after encountering a 223m continuous “oil show” into the deeper limestones/carbonates.

Log analysis by Weatherford, and also RPS, suggests potential pay of between 39.2m and 12.1m. This suggests volumes in the range of 0.4 – 2.5MMm bbls. We note that the ‘300m down dip’ Blina oil field, located 7km to the west, has produced 1.9MM bbls from an original estimated oil-in-place of some 5.6MM bbls. The deeper section below 1700m also has USG potential.

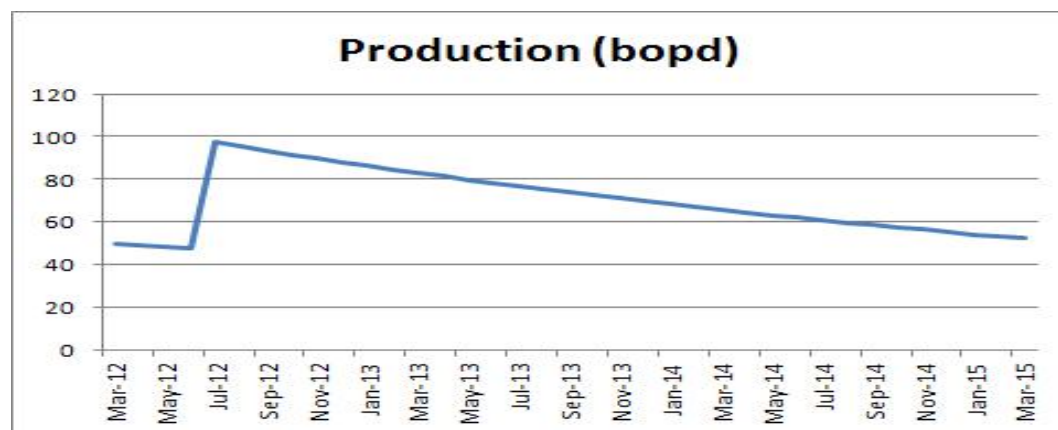


Source: OBL Limited

We have assumed OBL will test the Backreef-1 well in March 2012 (post the “rainy season”). In the event of success, we think the small discovery could produce 50 bopd/well, however, the real value of a successful test

would be the de-risking of the newly mapped potentially large oil play and for OBL to immediately “Declare a Location” over the Backreef Area. This may lead to the possibly exercise of “one-off” net 30% Backin Rights by titleholder Buru Energy Limited, by paying to OBL 90% all costs incurred to date (drilling, interpretation, well testing and completion) in the declaration of a discovery at Backreef-1 (under strict PRMS requirements).

The Backin Rights are expressly limited to the first well Backreef-1, and the quantum is estimated by OBL (after the cased hole test) at circa \$5.0 million. Ignoring this strategic potential upside of circa 1.5 cps, we estimate that even a modest 50 bopd result could be worth >\$3.5m in value to OBL.



Source: Gordon Capital estimates

OBL believes that Backreef-1 will need to be placed immediately on pump, and rates of 200 bopd could be worth >\$15m in value to OBL. The real value driver of the flow test is de-risking the remaining 7 leads within the permit.

OBL engaged RPS Energy to undertake a ‘peer review’ of its oil play within portions of the L6 and EP 129 “the Backreef Area”. In addition to the Backreef Lead, RPS mapped seven other lead closures 7 (in accordance with SPE’s PRMS Guidelines) targeting the up-dip Blina hydrocarbon prospective Yellow Drum formation, with significant “in place” and potentially recoverable oil volumes as follows:

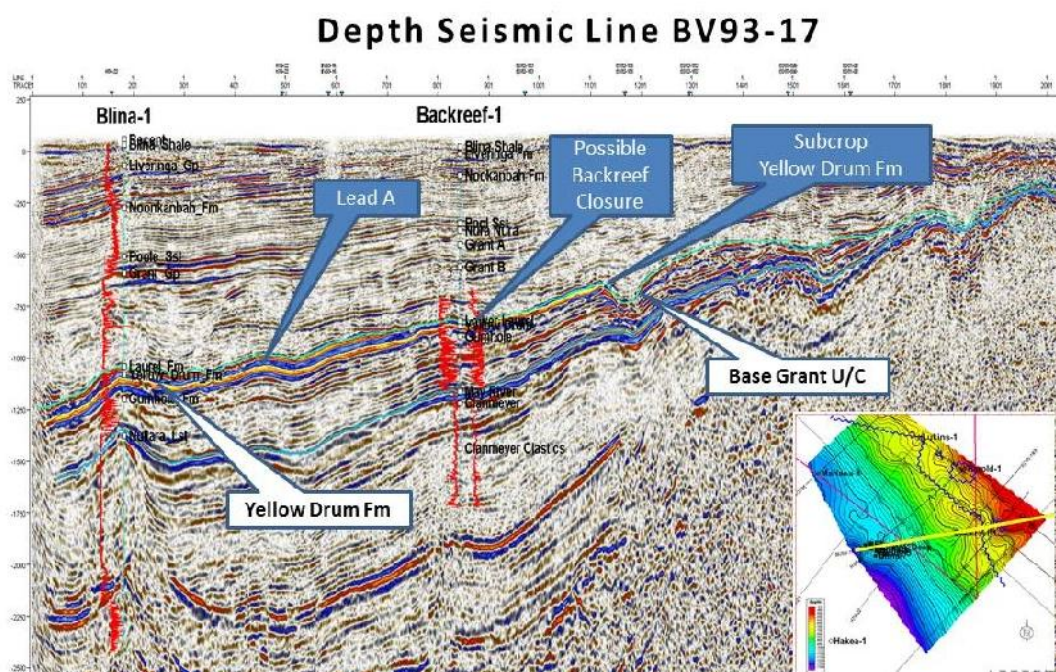
Lead	Undiscovered STOPIP		Prospectiv Resources (MMstb)					GPOs %	
	P90	P50	P10	Mean	Low	Best	High		Mean
A	1	1.86	3.08	1.97	0.18	0.47	0.96	0.49	8
Backreef	0.63	1.17	1.94	1.24	0.11	0.29	0.6	0.31	12
B	1.18	2.18	3.61	2.31	0.21	0.55	1.12	0.58	8
C	0.81	1.49	2.47	1.58	0.15	0.37	0.77	0.4	6
D	3.44	6.37	10.6	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	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	0.7	2.23	5.21	2.45	6
Total	45.6	72.8	117	77.7	8.95	17.7	35.7	20.6	

Source: OBL ASX release 23 November 2011

Given the Blina Field is currently economically productive, we estimate that the minimum economic recoverable volumes are circa 2-2.5 MMbbls “in place” (i.e. around 0.3 – 0.5 MM bbls recoverable). The Blina Field has shown recovery factors of 25%. This suggests at least four of the above leads (>15 MMbbls recoverable potential), while higher risk, would pass economic thresholds for drilling, and the block clearly has further exploration potential.

We note there is an TSX-listed exploration company (Gallic Energy), with a market capitalisation of circa \$32m, whose single exploration block in the Canning Basin adjoins OBL's Backreef Area immediately to the north and east (Meda Oil Pool) and it owns a shale play block in France, which is facing 'anti-fracking' regulations, hence the market is suggesting the company's value is determined by its Canning asset.

OBL has invested circa \$5.3m on the Backreef Area since 2006 (approx. \$4.5m on drilling of the Backreef-1 well in 2010). Given a discovery, potentially worth \$3.5m and substantial exploration potential (Backreef Area minimum 15 MMbbls prospective potential independently assessed by RPS Energy) and assuming a basin-wide probability of success (3%), this suggests a risked exploration value of \$4.5m. In the event of successful follow-up exploration at the Backreef Area, could see derisked values (using "in ground values" of between \$10-30/bbl) of \$150m-\$450m (43.4 cps plus).



Source: OBL Limited mapping

The above seismic line highlights a very important point:

- Moveable oil is present at the Backreef location;
- Seismic data indicates a roll over closure at "Lead A";
- Producing oil exists at Blina.

We suggest this means that "Lead A" (denoted East Blina-1 by OBL) is very likely to have received charge, and the key risk is therefore quality of the Yellow Drum reservoir in the event of moveable oil being discovered up-dip at Backreef-1.

OBL will seek farmin interest for some of the Backreef Area to production test the discovery and drill a second well by 31 October 2012 (East Blina-1 Prospect), with total costs estimated at circa \$2.3m to \$3.4m.

5/07-8EP (OBL 50%)

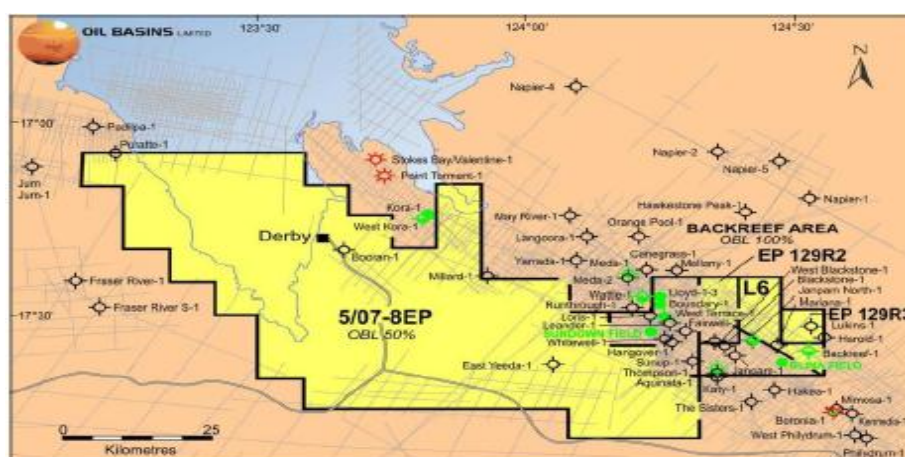
The permit, covering an area of 5062 km², is located within the Fitzroy Sub-basin, has very good potential for both CSG and USG plays, as well as conventional oil potential (a similar undrilled Embayment setting to the Backreef Area exists nearby the West Kora-1 Oil Pool). A maximum coal thickness of 20m (Permian Lightjack coal) was encountered over two main seams in the Booran 1 well. The following criteria must be met to be considered a viable shale-gas play:

- The shale sequences are thick;
- Are moderate to high in total organic content (TOC's) and thermally mature measured by vitrinite reflectance levels (VR) for gas, and are commonly over-pressured;
- May respond positively to "fracking" (calcite % and a marine origin are often important, as they generally have lower clay content and high silica content which may make the shale brittle);
- Must be regionally sealed, and typically are "very old rocks" to ensure both adequate depth of burial, and also temperatures to pass through the oil and gas window; note the majority of the successful seven North American USG plays are in rocks of marine origin and of Ordovician, Silurian and Devonian age.

A review of the publically available technical literature suggests that 5/07-8 EP meets all of these criteria.

Further, we have checked the published "in-place" gas prospective CSG resources, and our numbers are similar to that of Roger Meaney (Mapcourt Consulting).

The shale-gas play may have limited aerial extent within the permit, with depth of burial being the likely critical factor. Note a major erosional event has removed circa 2000m of sediments across most of the Canning Basin, and measured VR levels are higher than current depth of burial suggests. Additionally, the Booran-1 well (Esso - 1981) had excellent TOCs measurements in a basal shale (up to 10%), additionally the West Kora -1 well (Esso - 1982) some 20km to the north-east had similar TOCs. Two recent major farm-out deals suggest that 5/07-8EP has significant potential value, which we estimate in the range of \$20-40m value (based upon net free carried work program) assuming OBL's present 50% interest.



Source: OBL AGM Presentation

USG - SHALE GAS AN INTRODUCTION

Australia has very large shale-gas potential in at least five main basins:

- Cooper-Eromanga Basins – BPT / ADE / STO / ORG / SXY and others;
- Perth Basin – AWE / NWE / ORG and others;
- Georgina-Beetaloo Basins – BKR / CPT and others;
- Canning Basin – BRU / NSE / OBL (within the Fitzroy Trough only) and others;
- Maryborough Basin – Blue Energy / ADE and others.

Four of these basins hold an estimated total 396 Tcf of technically recoverable shale gas resources as assessed by the US Energy Information Agency (EIA).

Table XIV-1. Shale Gas Reservoir Properties and Resources of Australia

Basic Data	Basin/Gross Area	Cooper Basin (46,900 mi ²)	Maryborough Basin (4,290 mi ²)	Perth Basin (12,560 mi ²)		Canning Basin (181,000 mi ²)	
	Shale Formation	Roseneath-Epsilon-Murteree	Goodwood/Cherwell Mudstone	Carynginia Shale	Kockatea Fm	Goldwyer Fm	
	Geologic Age	Permian	Cretaceous	Upper Permian	Lower Triassic	M. Ordovician	
Physical Extent	Prospective Area (mi ²)	5,810	1,555	2,180	2,180	48,100	
	Thickness (ft)	Interval	0 - 1,800	300 - 3,000	300 - 1,500	300 - 3,000	300 - 2,414
		Organically Rich	500	1,250	950	2,300	1,300
		Net	300	250	250	230	250
Depth (ft)	Interval	6,000 - 13,000	5,000 - 16,500	4,000 - 16,500	3,300 - 16,500	3,300 - 16,500	
	Average	8,500	9,500	10,700	10,000	12,000	
Reservoir Properties	Reservoir Pressure	Moderately Overpressured	Slightly Overpressured	Normal	Normal	Normal	
	Average TOC (wt. %)	2.5%	2.0%	4.0%	5.6%	3.0%	
	Thermal Maturity (%Ro)	2.00%	1.50%	1.40%	1.30%	1.40%	
	Clay Content	Low	Low	Low	Low	Low	
Resource	GIP Concentration (Bcf/mi ²)	105	110	107	110	106	
	Risked GIP (Tcf)	342	77	98	100	764	
	Risked Recoverable (Tcf)	85	23	29	30	229	

Source: US Energy Information Agency

The EIA considered the following in their shale-gas resources characterisation:

1. Conduct a preliminary review of the basin and select the shale gas formations to be assessed.
2. Determine the areal extent of the shale gas formations within the basin and estimate its overall thickness, in addition to other parameters.
3. Determine the 'prospective area' deemed likely to be suitable for development based on a number of criteria and application of expert judgment.
4. Estimate the gas in-place as a combination of 'free gas' and 'adsorbed gas' that is contained within the prospective area (important as it determines flow rates, and de-watering if required).
5. Establish and apply a composite 'success factor' made up of two parts: firstly a 'play success probability factor' which takes into account the results from current shale gas activity as an indicator of how much is known or unknown about the shale formation; secondly a 'prospective area success factor', which takes into account a set of factors (e.g., geologic complexity and lack of access) that could limit portions of the 'prospective area' from development.

The Canning Basin has the highest potential, arguably due to having the best quality source rocks (organically rich marine shales) and at least 3 separate thick shale intervals. The large Canning Basin in Western Australia has

deep, Ordovician-aged marine shales that roughly correlate with the “Bakken, Michigan, and Baltic” basins in the USA. In our view, this suggests parts of the Basin will have “wet gas” potential.

The following deals have been concluded in Australian shale-gas plays:

- June 2010 - Mitsubishi commits up to \$152m to farm-in to Buru Energy’s Canning Basin exploration projects;
- August 2010 - Bharat Petroleum Corporation Limited pays \$15m to farm-in to Norwest Energy’s Perth Basin exploration project;
- July 2011 - Hess Petroleum farm-in to Falcon Energy’s Beetaloo Basin exploration project;
- September 2011 - BG Group commits \$130m to farm –in to Drillsearch’s Cooper Basin exploration project;
- ConocoPhillips commits up to \$109.5m to farm-in to New Standard Energy’s Goldwyer Project (Canning Basin);
- November 2011 - Beach Energy launches \$75m takeover for Adelaide Energy (ADE), for both its Otway and more significantly, a 10% stake in the Nappamuri Trough shale play.

Both the Perth and Cooper Basins have a large amount of geological well data, and their shales lie under conventional gas production facilities (an economic advantage compared to more remote locations), but they are less likely to have associated liquids (condensates), due to a non-marine (lacustrine) depositional origin, and the Cooper is likely to have elevated CO₂ levels (due to depth of burial, and have less overall potential in terms of recoverable resources. The Cooper Basin is likely to be the first to develop due to initial resource bookings, infrastructure, and existing sales contracts.

Mapcourt has independently assessed the gross USG unrisks potential of Permit 5/07-8EP at circa 250 Tcf per shale (permit contains 6 stacked shale zones) and the shallower gross recoverable 2P CSG potential at circa 4 Tcf. OBL and its privately owned JV partner have advanced their Native Title negotiations in 2011, and OBL expects this to be resolved by mid-2012.

The 5/07-8 EP is attractive due to:

- Permit is known to contain both CSG and USG plays over an area of approximately 5,000 km²;
- The shale has relatively high TOCs, is prospective for liquids; and is likely to have high gas-in-place resources;
- The region has been subject to substantial historical erosion, hence the target zones are relatively shallow;
- The western edges of the Canning Basin has good road access, likely to reduce exploration and development costs;
- OBL would consider enabling an appropriately qualified partner to assume operatorship.

Any successful farm-in would immediately put a value on OBL’s residual interest in the Permit based initially on the funded work program value (ignoring exploration success).

DIRECTORS AND SENIOR MANAGEMENT

Kim W McGrath, Executive Chairman

Kim is a founding director of the Company. He is an internationally experienced resources finance and investment banking executive, has extensive legal expertise (legal roles with Comalco, and ICL, and Bell Resources) and was Company Secretary of Bank of America Australia, and has experience negotiating international lines of finance and business acquisitions, and in strategy and development as General Manager, Strategy and Planning with Industrial Equity.

During the mid 1990s Kim was based in London and worked on the restructure of companies in eastern Europe and particularly on major operations in CIS metals and oil trading, and associated financing in both London and Geneva.

Since returning to Australia in 1998, Kim continues to hold full practising certificates as a Solicitor in both England and Wales and in Victoria, as well as holding Australian accounting qualifications as a CPA. He has also completed the Advanced Management Programme at Oxford University and is a Fellow of the AICD where he has successfully completed their Company Directors Course Diploma. Kim is the former chairman of ASX listed Redbank Copper Limited and Strategic Energy Resources Limited and he remains a director of CVC Property Managers Limited.

Neil F Doyle, Director and Chief Executive Officer

Neil is an energy specialist, and a qualified engineer with post-graduate qualifications in geomechanics with significant drilling operations experience (BHP & Esso) both onshore and offshore in upstream oil & gas, and also held management positions in downstream refining products / LPG sector with Shell Australia.

Subsequently, he has held senior management roles at commercial, technical and business development levels with a number of diversified resources groups (including Bell Resources) and investment banks (including Potter Warburg & HSBC Bank) – specialising in energy related merger and acquisition, energy securities analysis and capital raising transactions. Neil has 13 + years experience in investment banking/corporate finance with JP-Morgan Chase and Patersons Securities, focussing on energy assets

Nigel Harvey, Non-Executive Director

Nigel has 20+ years experience in energy banking (The Chase Manhattan Bank, Barclays Bank and JP-Morgan Chase, Macquarie Bank), across credit and treasury and corporate finance. There he gained extensive crude oil and energy products markets, derivatives, risk management and wider commodity and financial derivatives and markets experience. He focussed on delivering tailored risk management and hedging solutions for producers, airlines and other clients across the Asia Pacific. He has since developed an independent market risk consulting practice. His previous background of almost a decade in business journalism covering the Middle East, its oil sector and related topics equipped him with strong industry knowledge. He is a member of the Australian Institute of Company Directors and the Society of Petroleum Engineers (SPE).

Melanie J Leydin, Company Secretary

Melanie is a Chartered Accountant and principal in a chartered accounting firm specialising in audit and company secretarial services. She has 15 years experience in the accounting profession and is a director and company secretary for a number of junior mining and exploration entities listed on the Australian Stock Exchange.

Geoff Geary, Consultant Geologist

Geoff has 26+ years experience (Oil Company of Australia and Mobil Oil) in the oil industry across all facets of exploration assets (basin analysis, sequence stratigraphy, structural geology, seismic interpretation, basin modelling and oil and gas field evaluation and development).

VALUATION OF EXPLORATION ASSETS

The E&P typically uses one of three methods to value “Exploration Assets”:

- Farm-in Valuation
- Expected Monetary Value (EMV)
- Rules of Thumb

We have used Expected Monetary Value (where data is available on prospect sizes, well costs and timing). Where data is not available, recent trade sales and/or farm-in values can provide “guidance”. Note that the equities market tends to “pays for” one well at a time, rather than a portfolio of exploration assets.

Farm-in Valuation:

This is the “price” that a third party is willing to pay for entry into an exploration play.

Value = (1-% of acreage farmed out) * Amount being Spent.

For example, Beach Energy (BPT) is farming into some of Lakes Oil acreage, by spending \$10m to earn an initial 15% stake. This implies the acreage is valued at circa \$66.6m. Given the mapped volumes at Trifon and Wombat fields is some 1500 Pj’s, this implies 15-20c per Gj “in the ground for discovered resources”.

Expected Monetary Value:

The EMV concept is what is the expected financial outcome of an exploration programme, based on success ratios (probability of success), drilling costs (\$m/well), and field size (volumetrics) to derive an index of expected profitability (\$/boe).

The table on page 21 shows the volumetrics, probabilities which drive the EMV calculations.

Rules of Thumb:

Recent asset sales, cost of acquisition of permits from State / Federal Governments, seismic acquisitions costs, lease costs per acre can all used as guides in valuing acreage.

Geological risk is normally defined as the multiplication of:

- Risk of source rocks having generated hydrocarbons
- Risk of a suitable trapping mechanism
- Risk of a suitable sealing mechanism
- Risk of a suitable reservoir

THE CANNING BASIN

The 234,000 sq mile (approximately 150,000 sq miles is onshore) Canning Basin initially developed in the Early Paleozoic as an intra-cratonic sag between the Precambrian Pilbara and Kimberley Basins. Two major north-westerly faults separate the troughs (Fitzroy Trough, Willara and Kidson sub-basins) from an arch and marginal shelves. The Canning contains up to 18 km of Ordovician to Cretaceous age sedimentary rocks. The first commercial oil discovery was made only in 1981. Initial exploration focused on the Lennard Shelf, source rock data analysis is quite limited, but strongly suggest the oil fields discovered to date likely were sourced by the Carboniferous Laurel Formation shale. Most of the drilling has targeted the Devonian reefs and Permian–Carboniferous strata. The basin is substantially under explored.

In the EIA report, the Fitzroy Trough in the northern portion of the Canning basin contains thick, deep, thermally mature Goldwyer Formation source rocks, with an estimated resource concentration of approximately 106 Bcf/mi². Buru Energy has also reported gas-mature, organic-rich shale in cores from the Laurel formation.

The southern trough (Kidson and Willara Sub-basins) is thought to have thinner sedimentary successions (4–5 km thick) of predominantly Ordovician to Silurian and Permian age, with extensive Mesozoic cover.

Shell has tested the “subsalt Ordovician section” recovering hydrocarbons at its Looma 1 discovery in the southern Canning Basin.

The EIA resource assessment estimated the following factors for its shale-gas resource study:

1. The risked gas in-place estimate is derived by first estimating the amount of ‘gas in-place’ resource for a prospective area within the basin, and then de-rating that gas in-place by factors that, in the consultant’s expert judgment, account for the current level of knowledge of the resource and the capability of the technology to eventually tap into the resource. This estimate is referred to as the “risked gas in-place”, determined from the following specific steps.
 - Conduct a preliminary review of the basin and select the shale gas formations to be assessed.
 - Determine the areal extent of the shale gas formations within the basin and estimate its overall thickness, in addition to other parameters.
 - Determine the ‘prospective area’ deemed likely to be suitable for development based on a number of criteria (TOC / thermal maturity / depth of burial / types of organic material – which determines gas prone or oil prone) and application of expert judgment.
2. Estimate the gas in-place as a combination of ‘free gas’ and ‘adsorbed gas’.
3. Establish and apply a composite ‘success factor’ made up of two parts. The first part is a ‘play success probability factor’ which takes into account the results from current shale gas activity as an indicator of how much is known or unknown about the shale formation. The second part is a ‘prospective area success factor’, which takes into account a set of factors (e.g., geologic complexity and lack of access) that could limit portions of the ‘prospective area’ from development.

Preliminary geological and reservoir data are assembled for each major shale formation, including the following key items:

- Depositional environment of shale (marine versus non-marine)
- Depth (to top and base of shale interval)
- Structure, including major faults
- Gross shale interval
- Organically-rich gross and net shale thickness
- Total organic content (TOC, by wt.)
- Thermal maturity (Ro)

These geologic and reservoir properties are used to provide a first order overview of the geologic characteristics of the major shale gas formations and to help select the shale gas formations deemed worthy of more intensive assessment.

Marine-deposited shales tend to have lower clay content and tend to be high in brittle minerals such as quartz, feldspar and carbonates. Brittle shales respond more favourably to hydraulic stimulation. Shales deposited in non-

marine settings (lacustrine, fluvial) tend to be higher in clay, more ductile and less responsive to hydraulic stimulation.

APPENDIX AND GLOSSARY OF TERMS

M Thousand

MM Million

B Billion

bbl Barrel of crude oil (equal to 42 US gallons or approx 159 litres)

PJ Peta Joule (1,000 Tera Joules (TJ))

Bcf Billion cubic feet

Tcf Trillion cubic feet (i.e. 1,000 Bcf)

AICD - Australian Institute of Company Directors

BOE6 Barrel of crude oil equivalent – commonly defined as 1 TJ equates to circa 158 BOE – approximately equivalent to 1 barrel of crude equating to 6,000 Bcf dry methane on an energy equivalent basis)

PSTM Pre-stack time migration – reprocessing method used with seismic.

PSDM Pre-stack depth migration – reprocessing method used with seismic converting time into depth.

AVO Amplitude versus Offset, enhancing statistical processing method used with 3D seismic.

TWT Two-way time

CSG - Coal seam gas (CSG) or coal seam methane (CSG) is natural gas sourced from coals produced during the creation of coal from peat. The methane in CSG is adsorbed onto the surface of micropores in the coal, which increases with pressure/depth of burial.

USG Unconventional Shale Gas

STOIPP Stock Tank Oil Initially In Place – stabilised crude at atmospheric pressure

Boe – Barrel of oil equivalent (1000 standard cubic foot of gas = 1/6 bbl)

Mcf – 1000s of cubic feet of natural gas (normally quoted on a daily flow rate basis)

MMscf – millions of standard cubic feet of gas

Ac – acre (1 Ac = 4046.8 sq meters, 640Ac = 1 sq mile),

Hectares - equal to 10,000 square meters (equivalent to 2.471 acres)

J (Joule) – defined to be the work done by a force of one newton acting to move an object through a distance of one meter in the direction in which the force is applied. (Equivalent to 0.2388 calories.)

Tj – tera joule (10¹² joules)

ORRI – Overriding royalty interest

Operator – the entity within a Joint Venture that actually operators the underlying assets on behalf of the JV and is paid a fee for this.

Amplitude anomaly – An abrupt increase in seismic amplitude that can indicate the presence of hydrocarbons, although such anomalies can also result from processing problems, geometric or velocity focusing or changes in lithology. Amplitude anomalies that indicate the presence of hydrocarbons can result from sudden changes in

acoustic impedance, such as when a gas sand underlies a shale, and in that case, the term is used synonymously with hydrocarbon indicator.

API gravity – API Gravity is the industry standard for expressing the specific gravity (SG) of crude oils, and is actually an arbitrary scale devised jointly by the American Petroleum Institute and the National Bureau of Standards. Oil with the least specific gravity has the highest API gravity.

Drill Stem Test (DST) – the controlled flowing of the fluids from a reservoir so that estimates of the flow rate and fluid type can be made. It is usually conducted for a short time only (typically 4 – 6 hours), and can be run in open hole or through perforations in cased hole.

EMV – EMV risk adjusts the value of the discovery (i) – related to the recoverable volume of the discovery (V) and the discounted average oil price over the life of the field (P) – to the risk capital (C) and the probability that the prospect will succeed (U), according to the following equation:

$$\bullet (EMVi = ViP)U i W (Ci(1W U i))$$

The Expected Monetary Value (EMV) calculation, while not used as a valuation tool, provides a useful “sanity check”.

Farm-in – The process of buying in to a licence block held by another licensee by paying a proportion of the costs, normally in excess to the interest that is finally earned. E.g., earning a 15% interest on a 2:1 basis means that 30% is paid.

Gas-in-Place (GIP) – an estimated measure of the total amount of gas contained in a reservoir and, as such, a higher figure than Recoverable Gas.

OOIP – Original oil in place.

NPV (10) – The present value of reserves booked and audited based on the prevailing fiscal assumptions. In the case of an exploration company, the NPV reserves are assumed to be the risked reserves as outlined by the competent persons report.

Pay – A net reservoir interval containing moveable (recoverable) hydrocarbons – defined as gross (total hydrocarbon column) and net (producibile hydrocarbon column – see definition of permeable).

Permeability – Is the extent to which a solid allows the flow of a fluid. This flow depends on the properties of the solid and also on the dynamic viscosity of the fluid and the difference in pressure driving the flow, and is widely measured in darcies or millidarcies.

Prospect – Potential accumulation that is sufficiently well defined to represent a viable drilling target.

Reservoir – A subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. Sedimentary rocks are the most common reservoir rocks because they have more porosity than most igneous and metamorphic rocks and form under temperature conditions at which hydrocarbons can be preserved.

Lead Potential – An area where one or more accumulations are currently poorly defined and require more data acquisition and/or evaluation in order to be classified as a prospect. A lead will occur within a play (see prospect).

Recovery (factor) – The fraction of hydrocarbons that can or has been produced from a well, reservoir or field from the in-place volumes.

Risk – The probability of loss or failure. As “risk” is generally associated with the negative outcome, the term “chance of success – COS or POS” is preferred for general usage to describe the probability of a discrete event occurring.

Royalty – Refers to payments that may be due to the host government, mineral owner, or landowner, in return for the producer having access to the petroleum. Many agreements allow for the producer to lift the royalty volumes, sell them on behalf of the royalty owner.

Seismic – Pertaining to waves of elastic energy, such as that transmitted by Pwaves and Swaves, in the frequency range of approximately 1 to 100 Hz. Seismic energy is studied by scientists to interpret the composition, fluid content, extent and geometry of rocks in the subsurface.

- **2D** – A group of seismic lines acquired individually, as opposed to the multiple closely spaced lines acquired together that constitute 3D seismic data.
- **3D** – A set of numerous closely-spaced seismic lines that provide a high spatially sampled measure of subsurface reflectivity. The receiver line spacing can range from 300 m to more than 600 m.

Trap – A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate. Traps are described as structural traps (in deformed strata such as folds and faults) or stratigraphic traps (in areas where rock types change, such as unconformities, pinch-outs and reefs).

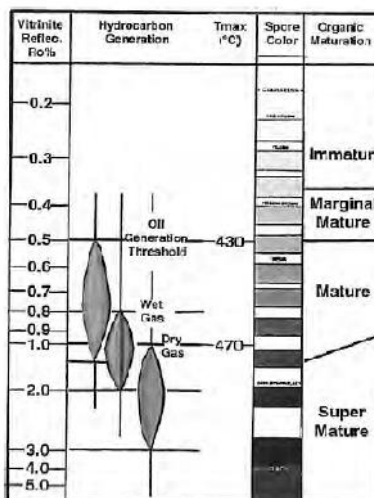
EUR - Expected Ultimate Recovery – this is one of the principal economic drivers for oil and gas companies.

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- World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States, prepared by Advanced Resources International for the U.S. Energy Information Administration, April 2011
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THERMAL MATURITY LEVELS

Figure 2-6. Thermal Maturation Scale

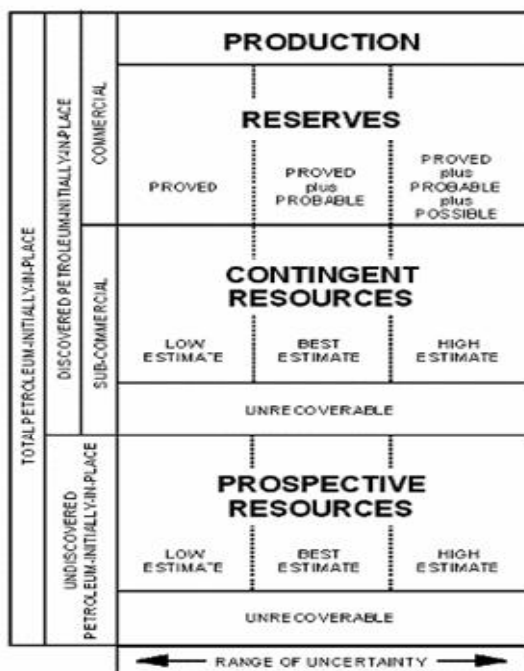


Reserves and Resources – Classification

1P – (Proven oil reserves) are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped. 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.

2P – (Probable oil reserves) are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

3P – (Possible oil reserves) are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.



Not to scale

Source: AAPG Reporting Guidelines.

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