EXOIL LIMITED

ABN 40 005 572 798

www.exoil.net

Information Memorandum in support of an Application for Listing on National Stock Exchange of Australia Limited ("NSX")

No offer of securities is being made pursuant to this Information Memorandum.

AN INVESTMENT IN THE COMPANY'S SECURITIES SHOULD BE CONSIDERED SPECULATIVE

This Information Memorandum is an important document and should be read in its entirety.

This Information Memorandum is not a Prospectus or an Offer Information Statement ("OIS"): both of which are disclosure documents under the Corporations Act 2001. Consequently, it should be regarded as having a lower level of disclosure than a Prospectus or an OIS.

CORPORATE DIRECTORY

DIRECTORS

James Willis (Chairman)
E Geoffrey Albers
Pamela Albers
Graeme Menzies

COMPANY SECRETARY

Jack Tuohy

REGISTERED OFFICE AND PRINCIPAL ADMINISTRATION OFFICE

Level 21, 500 Collins Street,
Melbourne, Victoria 3000, Australia
Telephone: +61 (0)3 8610 4700
Facsimile: +61 (0)3 8610 4799
E-mail: admin@exoil.net
Website: www.exoil.net

AUDITOR AND INDEPENDENT ACCOUNTANT

PKF
Chartered Accountants
Level 14, 140 William Street,
Melbourne, Victoria 3000

SPONSORING BROKER AND NOMINATED ADVISOR

Pritchard & Partners Pty. Limited
(AFS) Licence Number 246712
10 Murray Street,
Hamilton, NSW 2303
Telephone: +61 (0)2 4920 2877
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SHARE REGISTRY

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FORWARD LOOKING STATEMENTS

Various statements in this Information Memorandum constitute statements relating to intentions, future acts and events. Such statements are generally classified as forward looking statements and involve known and unknown risks, uncertainties and other important factors that could cause those future acts, events and circumstances to differ from the way or manner in which they are expressly or implicitly portrayed herein.

SUITABILITY OF INVESTMENT AND RISK FACTORS

Before deciding to invest in the Company following its admission to the Official List of NSX, Proposing Investors should read this entire Information Memorandum and, in particular, the summary of the Company's business in Section 4 and the risk factors in Section 8. They should carefully consider these factors in the light of their personal circumstances (including financial and taxation issues) and seek professional advice from their accountant, stockbroker, lawyer or other professional advisor before deciding to invest.

STRUCTURE OF THIS INFORMATION MEMORANDUM

The content of this Information Memorandum is outlined in the Table of Contents above and any reference to a "Section" is a reference to the relevant numbered Section of this Information Memorandum. Readers are particularly referred to the definitions (capitalised terms), glossary and abbreviations that are contained in Section 11 to assist in their understanding of the contents of this Information Memorandum.

SECTION 1: CHAIRMAN'S LETTER

Exoil Limited
ABN 40 005 572 798

Level 21
500 Collins Street
Melbourne Victoria 3000 Australia

Tel: (+61 3) 8610 4700
Fax: (+61 3) 8610 4799
Email: admin@exoil.net

Dear Member

This Information Memorandum is issued in support of an application by Exoil Limited for listing on the National Stock Exchange of Australia Limited ("NSX"). It contains detailed information about the Company's financial position, petroleum exploration permits and operations. While this is not a capital raising document, Members and Proposing Investors are encouraged to read this Information Memorandum in full and to seek professional advice before deciding whether to invest or trade in the shares of the Company following its admission to the Official List of NSX.

The Board foreshadowed seeking this listing last year and confirmed the exercise was well advanced via my "Chairman's Review" within the latest annual report. A copy of that annual report is included as Section 9 of this Information Memorandum. As that annual report was so recently released, it contains an up-to-date commentary on the current status of the Company's operations within the 12 Permits in which it has an interest. You are thus pointed to my Review and to the Directors Report for that commentary.

Operations continue at a pace, with the next milestone being the Spikey Beach 1 well to be drilled in T/38P in the Bass Basin, offshore Tasmania. That well is now due to spud in late December, having been delayed due to minor rig damage when moving off a recently completed well.

There may also be a well drilled during the first quarter of 2009 (in WA-359-P, Dampier Basin, offshore Western Australia), should MEO Australia Limited commit to this as provided in the farmout to that company of part of Exoil's interest in that licence.

The Braveheart 1 well is planned for later in 2009 within WA-333-P, Browse Basin, offshore Western Australia.

As well as these planned wells, there is a significant amount of work being progressed across other of the Company's 12 Permits and this is described in this Information Memorandum in Section 4.

To reiterate, Members and Proposing Investors should read this Information Memorandum in full and take professional advice if you are considering investing in the Company's shares.

Yours sincerely

James Willis
Chairman

12 November 2008

SECTION 2: IMPORTANT INFORMATION

STATUS AND NATURE OF THIS INFORMATION MEMORANDUM

No offer of securities is being made pursuant to this Information Memorandum. This Information Memorandum is for information purposes only. A copy will be lodged with NSX and a copy will be placed on the Company's website www.exoil.net to enable interested parties to access same.

ASIC

No copy of this Information Memorandum has been lodged with the Australian Securities and Investments Commission ("ASIC").

This Information Memorandum is not a prospectus nor is it an Offer Information Statement ("OIS"): both of which are disclosure documents under the Corporations Act 2001 ("Act") and which must be lodged with ASIC.

Consequently, this Information Memorandum should be regarded as having a lower level of disclosure than a prospectus or an OIS.

ASIC takes no responsibility for the contents of this Information Memorandum.

APPLICATION FOR LISTING

The Company will apply to **National Stock Exchange of Australia Limited ("NSX")** within 7 Business Days of the date of this Information Memorandum for admission to the Official List and for Official Quotation of its securities on NSX.

The fact that NSX may list the securities of the Company is not to be taken in any way as an indication of the merits of the Company or the listed securities.

NSX takes no responsibility for the contents of the Information Memorandum, makes no representations as to its accuracy or completeness and expressly disclaims any liability whatsoever for any loss arising from or in reliance upon any part of the content of the Information Memorandum.

It is expected that trading of the Shares on the stock market conducted by NSX will commence as soon as practicable after approval for admission to the Official List of NSX is granted and all conditions (if any) applicable thereto have been satisfied for Official Quotation.

FORWARD LOOKING STATEMENTS

Various statements in this Information Memorandum constitute statements relating to intentions, future acts and events. Such statements are generally classified as forward looking statements and involve known and unknown risks, uncertainties and other important factors that could cause those future acts, events and circumstances to differ from the way or manner in which they are expressly or implicitly portrayed herein.

SUITABILITY OF INVESTMENT AND RISK FACTORS

Before deciding to invest in the Company by purchase of Shares on market, following admission of the Company to the Official List of NSX, Proposing Investors should read this entire Information Memorandum and, in particular, the summary of the Company's business activities contained in Section 4, the Independent Expert's report from Michael J. Martin, Consultant Petroleum Geologist, relating to the Company's Permits which is contained in Secton 7, the financial information contained in Section 5, the audited accounts of the Company as at 30 June 2008 with the Auditor's Report thereon contained in Section 9 togerther with the unaudited management accounts of Exoil as at 30 September 2008 together with the risk factors contained in Section 8.

Proposing Investors should carefully consider all these factors in the light of their personal circumstances (including financial and taxation issues) and seek professional advice from their accountant, stockbroker, lawyer or other professional advisor before deciding to invest. They should understand that exploration for oil and gas is both speculative and subject to a wide range of risks and that, unless the Company makes a commercial discovery, they may lose the entire value of their investment.

The Company is unable to advise any Proposing Investor on the suitability or otherwise of an investment in the Company. For such advice each Proposing Investor must contact their own independent professional adviser(s).

ELECTRONIC INFORMATION MEMORANDUM

This Information Memorandum may be viewed and downloaded online at the Company's website www.exoil.net.

NATIONAL STOCK EXCHANGE OF AUSTRALIA LIMITED

NSX was the second stock exchange approved under the then Corporations Law in Australia (February 2000) and is licensed under the Financial Services Reform Act 2001, which came into effect on 11 March 2002. NSX is a fully operational and fully regulated stock exchange. NSX publishes substantial information about itself and the market on its website www.nsxa.com.au.

NSX creates a market for a wide range of interests including alternative investments and traditional equity securities based on corporate listings. The investments listed by NSX cover various areas of the economy that require a market platform. NSX is focused on listing small to medium enterprises, as there is a great need for growth entities to have a capital market where they can raise further capital and provide a mechanism for the transferability of shares or other listed interests.

Brokers dealing on NSX

There are 14 member brokers registered as Participant Brokers of NSX - they are the only brokers who can execute trades on NSX. Full profiles of each Participant Broker are available on the NSX website under the 'For Brokers' tab. The Participant Broker network offers access to, and promotion of, stocks on NSX.

Availability of CHESS reports about holdings

Presently all NSX securities are registered in CHESS (see below for explanation of CHESS) and standard CHESS reports are available for securityholders.

Obtaining share prices for NSX quoted securities

Share prices are available from a variety of sources. Participating Brokers can obtain full market information from the NETS screens, plus IRESS and AAPO carry end of day information as part of their news services. For investors, the NSX website carries price updates every 20 minutes as well as daily and monthly price histories on each stock. The Australian Financial Review carries daily trading information and month to date summaries are published each Monday in the Market Wrap section.

Status of NSX

NSX is a full main board exchange. NSX concentrates on listing small to medium enterprises and has Listing and Business Rules approved by ASIC (see the ASIC website www.asic.gov.au). All entities listed on NSX must comply with these rules. NSX is not the same as the Second Board that existed in Australia in the late 1980's and early 1990's

The role of Nominated Advisers

Companies intending to list on NSX are required to have a Nominated Adviser and a Sponsoring Broker. It is contemplated that, with a Nominated Adviser for each entity, investors will be offered better protection because Nominated Advisers are required to make sure that companies meet the on-going requirements for listing and the requirements of the Act. The Company has appointed Pritchard & Partners Pty. Limited (AFS) Licence Number 246712 as Nominated Advisor and Sponsoring Broker.

CHESS

The Company will apply to participate in the Clearing House Electronic Sub-register System known as CHESS. ASX Settlement and Transfer Corporation Pty Ltd, a wholly owned subsidiary of ASX Limited, operates CHESS in accordance with the Listing Rules and Shares Clearing House Business Rules.

On admission to CHESS, the Company will operate an electronic issuer-sponsored sub-register and electronic CHESS sub-register. The two sub-registers together will make up the Company's principal register of shares.

The Company will not issue certificates to securityholders.

A CHESS Holding Statement or Issuer Sponsored Holding Statement will routinely be sent to securityholders at the end of any calendar month during which the balance of their holding changes. A securityholder may request a holding statement at any other time, although a charge may be made by the Share Registry, Link Market Services Limited, for additional statements.

INFORMATION

No person is authorized to give any information or to make any representation in connection with this Information Memorandum which is not contained in this Information Memorandum. Any information or representation not so contained may not be relied upon as having been authorized by the Company for any purpose and may not be relied upon for any purpose whatsoever.

JURISDICTION

This Information Memorandum does not constitute an offer or invitation to buy or sell shares or other marketable securities of the Company, whether in Australia or in any other jurisdiction.

PROPERTY OF THE COMPANY

Unless otherwise stated, assets and property portrayed in photographs in this Information Memorandum are not owned by the Company.

DATE OF INFORMATION MEMORANDUM

This Information Memorandum is dated 12 November 2008.

SECTION 3: KEY FEATURES AND HIGHLIGHTS

Exoil carries on oil and gas exploration in the offshore margins of Australia. The Company is managed by the Directors and Company Secretary with the support of outside consultants. See Section 6 for details of the qualifications and experience of these persons.

The Company's petroleum exploration activities are set out in Section 4, while Section 7 contains the Independent Expert's report from the Consultant Geologist. A summary of the Company's financial information is at Section 5 and detailed audited Financial Statements as at 30 April 2008 are contained in Section 9.

The Company carries on high risk activities, with details of the known risks set out in Section 8. General matters, including the Directors' and Officer's interests, are set out in Section 10.

STRATEGY - OIL FOCUS

The Company's strategy is to acquire and control strategic areas prospective for oil in offshore waters within the jurisdiction of Australia. The Board recognises that the Company lacks the resources to fully explore and develop the areas on its own behalf. This is why the Company will seek opportunities that have significant potential to be farmed out and/or developed in conjunction with major industry players.

EXPERIENCED BOARD

The Board has:

- experience in the oil and gas and resource industries.
- a proven track record of creating value for shareholders.
- a commitment to standards of corporate governance.

DIVERSITY OF PROJECTS

Exoil provides the following diversity of activity exposure:

Bass Basin – T/38P – 35% (10% in Spikey Beach Blocks)

- **Spikey Beach-1 well to be drilled in late December 2008.**
- More than 600 line kms of new, high quality 2D seismic just acquired.
- Various fault block oil plays.
- Nearby to Trefoil-1 gas discovery.
- Close to southeast Victoria gas markets.
- Contains known Pelican gas occurrence (5 wells).
- Rich liquids and gas source seem apparent.

Gippsland Basin – Vic/P45 – 50%

- **Potential to farm down.**
- Strong oil potential.
- Approximately 1,100 kms^2 of modern 3D seismic shot in 2003.
- More than 10 leads and prospects remaining to be assessed.
- Existing oil/gas discoveries at Archer/Anemone.
- Close to under-utilised oil infrastructure.

Bass Basin – T/37P – 35%

- **More than 3,000 line kms of new, high quality 2D seismic just acquired.**
- 3 previously recognised leads in the Permit – scope for considerably more with new seismic.
- Adjacent to Yolla Gas/Condensate Development.
- Significant oil shows in Tilana-1 within the Permit.

Gippsland Basin – Vic/P53 – 16.6667%

- **West Cod oil potential.**
- Multiple oil and gas target potential.
- Heart of prolific oil producing Gippsland Basin, experiencing resurgent development and exploration.
- 3D seismic technology used to provide a new opportunity to uncover 'hidden' prospectivity.
- Pivotal location in eastern Australia, close to established markets and major population centres.
- Growing niche as Gippsland Basin emerges from ESSO/BHP dominance.
- Opportunities of significant scale for smaller entities.
- Nearby to under-utilised oil infrastructure including pipelines and processing plant.
- No well drilled in the Permit area for 18 years.

Browse Basin – Browse Joint Venture Permits (WA-332-P, WA-333-P, WA-342-P) – 35%

- **Braveheart structure across WA-332-P and WA-333-P defined: planned to be drilled in Q3 2009. See RPS Energy Report in Section 7**
- Slot on the Songa Venus drilling vessel secured to drill Braveheart-1 well.
- Braveheart well 2D infill seismic survey about to be acquired.
- International industry interest in the region.
- Strong oil potential.
- Huge amount of 3D seismic available in Cornea area (in WA-342-P).
- Contains the Cornea oil/gas occurrence, Gwydion oil occurrence immediately to the south.
- Established petroleum province.

Dampier Basin/Rankin Trend – WA-359-P – 20%

- **MEO Australia Limited Farm-in: by 31 December 2008, MEO must elect to drill a well or assign 30% Permit interest back to Exoil.**
- Both oil and gas potential.
- Only 8 kms from Mutineer/Exeter oil complex.
- Nearby to Hermes, Lambert and Wanaea Oilfields.
- Adjacent to the multi-TCF gasfields of the Rankin Trend: North Rankin, Perseus and Goodwyn.
- Only one well drilled on the fringe of the Permit.
- An unexplored area in close juxtaposition to giant fields.
- Close to both gas and oil infrastructure.

Otway Basin – EPP34 – 15%; EPP35 and EPP36 – 30%

- **1,100 line kms Tropoca new 2D seismic acquired and more than 1,500 line kms of seismic to be reprocessed, all in EPP34.**
- Troas Deep prospect: gas play in EPP35.
- 325 km^2 of 3D seismic planned for EPP35.
- 1,100 line kms on new 2D seismic planned for EPP36.
- Oil and gas potential.
- Region lightly explored.
- Permits located in proximity to the Adelaide gas pipeline.
- Frontier area with potential for large accumulations in new play types.

Otway Basin – Vic/P61 – 30%

- **Adjacent to developing infrastructure and new gas developments at Casino, Minerva, Geographe and Thylacine.**
- Located in commercial gas province.
- Potential for oil plays in Cretaceous and Tertiary play fairways.
- Close to markets, population centres and new infrastructure.
- Plans to acquire up to 1,000 line kms of new 2D seismic.

SECTION 4: THE COMPANY'S PETROLEUM EXPLORATION ACTIVITIES

Set out in this Section are details of the Company's interests in various Permits granted for exploration for oil and gas. Salient points relating to each Permit, the current status of that Permit and proposed activities in relation thereto are set out herein. The Permits are all initially issued for six years and the work obligations of each one is detailed in Section 12.

Geological data and information in respect of each Permit is more particularly set out in the Martin Report in Section 7.

Against the background information provided in the previous Section, and in this Information Memorandum generally, the Directors advise as follows in relation to the Company's interests in the Permits detailed.

VIC/P45 GIPPSLAND BASIN: OFFSHORE VICTORIA
50% INTEREST
OPERATOR: EXOIL LIMITED

The Vic/P45 Joint Venture consists of:

Exoil Limited	50%
Moby Oil & Gas Limited	50%

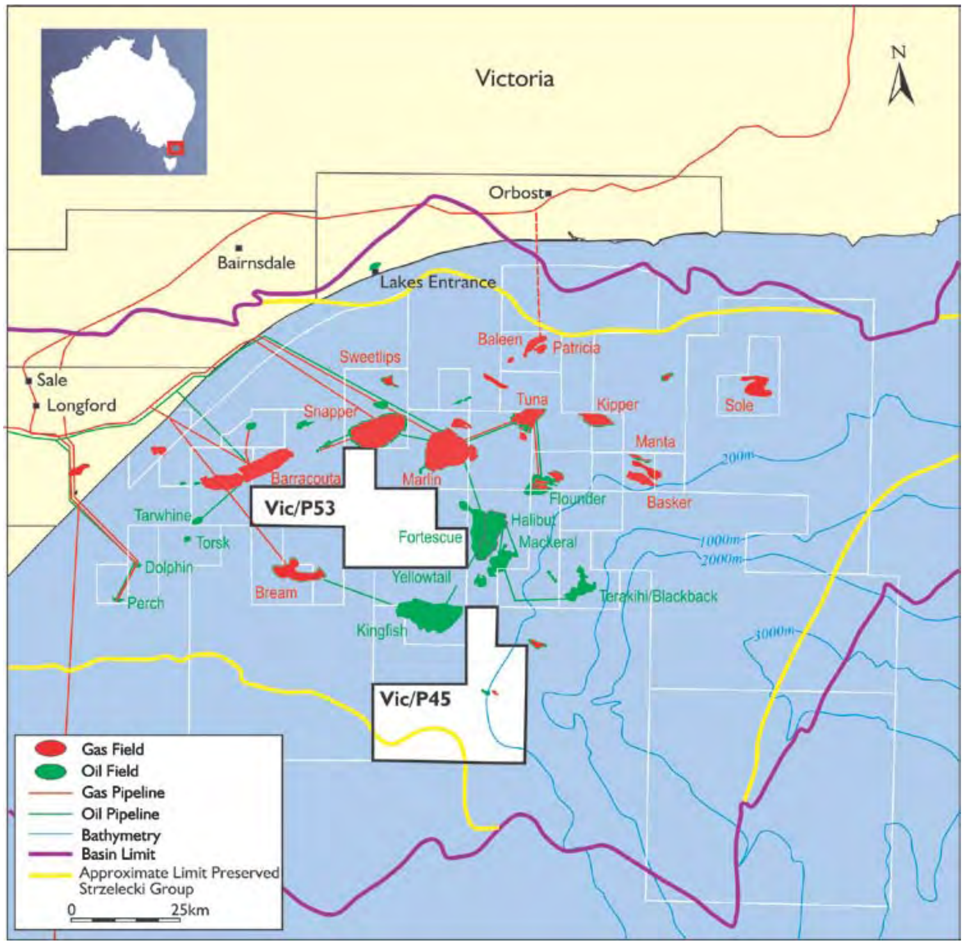

Figure 1 above shows the location of Vic/P45. For a geological description of Vic/P45 see the the Martin Report in Section 7.

Vic/P45 was previously farmed out to Apache Energy Ltd ("Apache") which drilled, at its cost, the Coelacanth-1 well in Q1 2008. Apache elected to withdraw from any further commitment to drill a second well and is now required to reconvey the farmout interest (66.6668%) to Exoil and Moby in equal shares.

Following Apache's withdrawal, application has been made to the Designated Authority to approve a program of office studies in 2008/2009, to be followed by a well in 2009/2010. The very tight market for offshore drilling rigs has pushed future Vic/P45 drilling activity into 2009/2010.

The remaining prospects are required to be upgraded to drillable status, which is the purpose of the office studies to be undertaken in 2008/2009, preparatory to drilling.

The Permit is not subject to Native Title claims

Budgeted Expenditure – VIC/P45

Year of Term of Permit	**Summary Work Program**	**Exoil's 50% Share of**	
		Budgeted Expenditure* A$	**Indicative Expenditure* A$**
		2008/2009	**2009/2010**
Year 4	Office Studies	10,000	100,000
Year 5	Drill One Well		NIL
TOTAL BUDGETED EXPENDITURE 2008/2009		10,000	
TOTAL INDICATIVE EXPENDITURE 2009/2010			100,000
* **ASSUMPTIONS:**	That the Designated Authority approves the program as submitted. That is, office studies in 2008/2009 to be followed by a well in 2009/2010. That the cost of the year 5 well will be met by farm out or that an election is made not to drill.		

VIC/P53 GIPPSLAND BASIN: OFFSHORE VICTORIA
16.6667% INTEREST
OPERATOR: STUART PETROLEUM LIMITED

The Vic/P53 Joint Venture consists of:

Stuart Petroleum Limited	50%	
Exoil Limited	16.6667%	
Moby Oil & Gas Limited	8.3333%	
Cue Petroleum Pty Ltd	25%	(15% of this interest is held by Cue Petroleum to meet ACOC back-in rights pursuant to an agreement between Cue Petroleum and ACOC [see explanation at Section 10.1.3].)

Figure 1 above shows the location of Vic/P53 (and of Vic/P45 referred to above). For a geological description of Vic/P53 see the Martin Report in Section 7.

Vic/P53 has been farmed out to Stuart Petroleum Limited ("Stuart"). As required under the terms of the farm out, Stuart was appointed Operator and drilled the Bazzard Prospect within Vic/P53 which was subsequently plugged and abandoned. To complete its earn in Stuart is required to meet 100% of the costs of two wells in the permit. Having drilled Bazzard 1 as the first well, Stuart has the right to withdraw from the Permit. The Company is presently awaiting Stuart's decision on whether to drill the second well or withdraw. Should Stuart withdraw from the Joint Venture, the Company's interest in the Permit would increase to 33.3334%.

Prior to the spudding of Bazzard-1, Stuart paid US$1,150,000 to Exoil and Moby (in the ratio of⅔ to Exoil and ⅓ to Moby). This enabled Exoil and Moby to meet their pre-existing contractual obligations to Cue Petroleum.

While Stuart remains in the Permit, it will assume its pro rata share of the overriding royalty (4%) obligations to ACOC relating to the Exoil and Moby interests.

VIC/P53 covers an area of 740.2km² and is overlapped by Native Title claim VC97/4 with the extent of overlap being 201.7km². The claim number is Federal Court No. VG6007/98; NNTT No. VC97/4. The name of the group claiming Native Title is Gunai/Kurnai people and the date of registration is 4 April 1997. For further information see the National Native Titles Tribunal website www.nntt.gov.au

Budgeted Expenditure – Vic/P53

Year of Term of Permit	**Summary Work Program**	**Exoil's 16.6667% Share of**	
		Budgeted Expenditure* A$	**Indicative Expenditure* A$**
		2008/2009	**2009/2010**
Year 3	Drill Two Wells	NIL	NIL
Year 4	Data Evaluation		33,333
TOTAL BUDGETED EXPENDITURE 2008/2009		NIL	
TOTAL INDICATIVE EXPENDITURE 2009/2010			33,333
* **ASSUMPTIONS:** Stuart drills two wells as per the farmin terms. In the event that Stuart elects not to drill the second well the Company will carry out a detailed evaluation of the data from Bazzard 1 and seek to roll over the obligation to drill the second well into year 4 obligations and, at the same time, seek farm out the second well obligation to a new farminee.			

T/37P AND T/38P BASS BASIN: OFFSHORE TASMANIA
35% INTEREST*
OPERATOR: CUE ENERGY RESOURCES LTD

(* Exoil and Cue interests to reduce to 10% in the Spikey Beach Blocks in T/38P in which Beach Petroleum Limited ("Beach") is to drill the Spikey Beach-1 well to earn an 80% interest in those blocks only. Gascorp holds no interest in the Spikey Beach Blocks.)

Each of the T/37P and T/38P are subject to separate Joint Ventures and each Joint Venture consists of:

Cue Energy Resources Ltd	50%
Exoil Limited	35%
Gascorp Australia Pty Ltd *	15%

Figure 2 below shows the location of both T/37P and T/38P. For a geological description of T/37P and T/38P see the the Martin Report in Section 7.

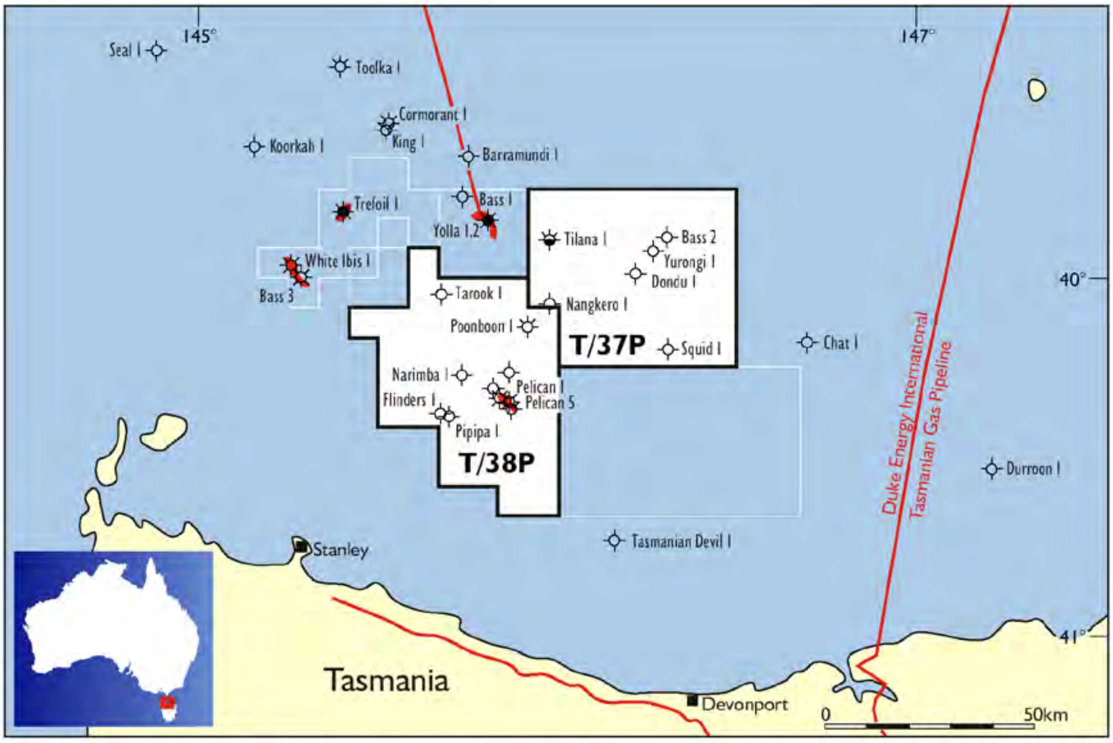

Figure 2. T/37P and T/38P Bass Basin, showing exploration wells, gas fields and pipelines.

The Joint Venturers hold two adjacent Permits, T/37P and T/38P, located in the Bass Strait region, north of Tasmania and east of King Island. Each area consists of 40 graticular blocks covering areas of approximately 2,670 kms² (T/37P) and 2,655 kms² (T/38P). Water depths across the areas are less than 75 metres.

The T/37P Permit is immediately adjacent to the Yolla gas/condensate field that has recently begun production. Yolla also contains oil.

Interpretation of the existing seismic data has been completed and both time and depth maps have been constructed and integrated with existing well information. Prospects and leads have been identified and have been analysed.

In early 2008, Exoil joined with a group of companies which together mobilized a seismic vessel to the Gippsland, Bass and Otway areas. 3,000 line kms of new 2D seismic data was acquired in T/37P and 660 line kms in T/38P. Exoil farmed out its share of costs of this survey to Gascorp Australia Pty Ltd and as a consequence, its interest in each of the Permits and the Joint Ventures has reduced to 35%.

The T/38P Joint Venture is the same make up as the T/37P Joint Venture but with the difference that Beach has agreed to farmin to 18 graticular blocks in T/38P (the Spikey Beach Blocks) and will earn an 80% interest in those blocks within the Permit by meeting the drilling costs of the Spikey Beach-1 exploration well. The Spikey Beach-1 exploration well will be operated by Beach and is expected to be drilled in the Q4 of 2008. See Figure 3 below showing the Spikey Beach Blocks and the location of Spikey Beach-1.

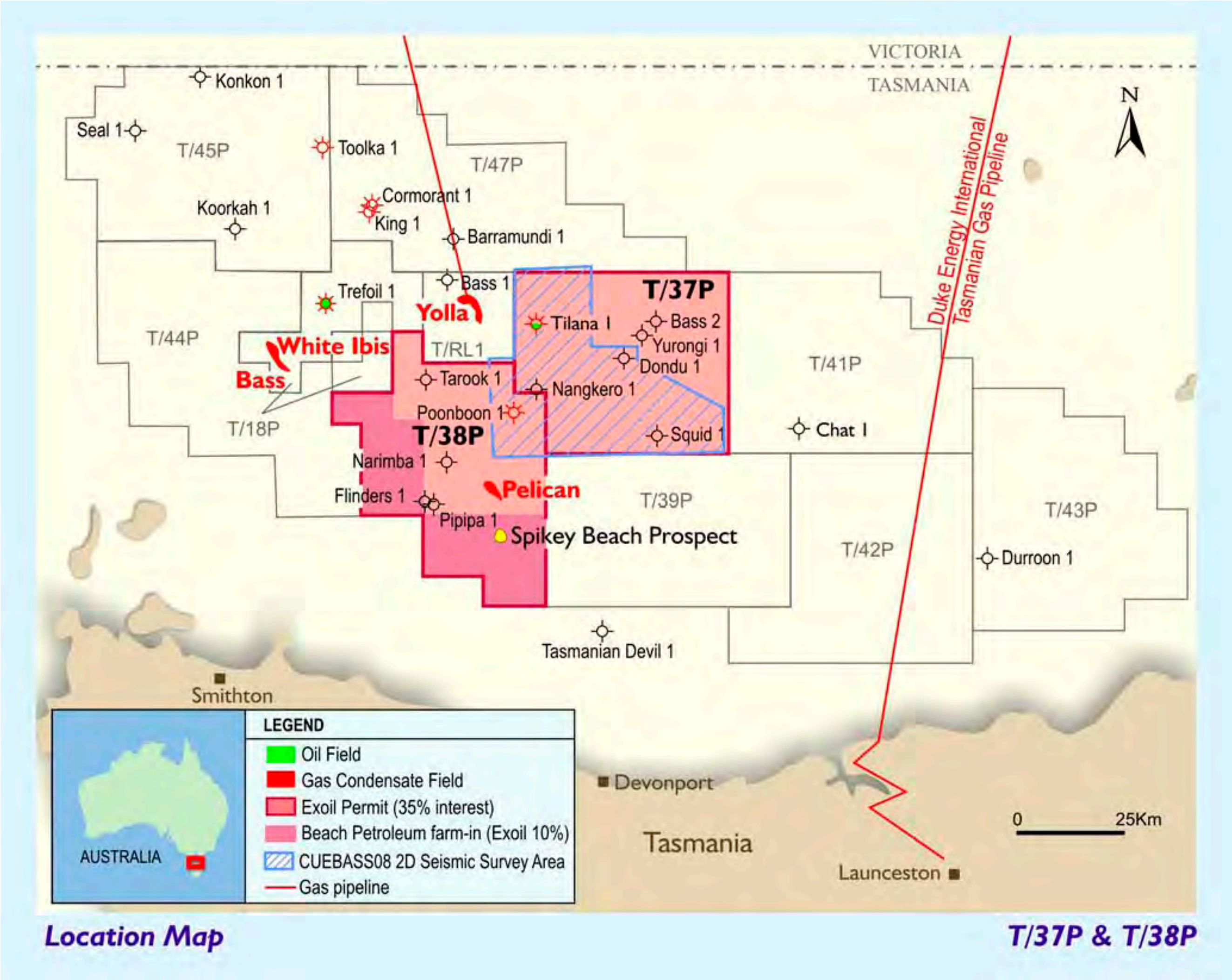

Figure 3. T38P showing Spikey Beach Blocks and the location of Spikey Beach-1

The T/38P Permit is immediately south of the producing Yolla gas/condensate field. The Permit contains the undeveloped Pelican gas/condensate discovery. Interpretation of the existing seismic data has been completed and both time and depth maps have been constructed and integrated with existing well information. Prospects and leads have been identified and have been analysed. The recent 2D seismic survey should provide more certainty of these interpretations.

The Bass Basin is a moderately explored basin with 33 wells drilled since 1965. The basin has a drilling density of approximately one well per 1,320 kms².

The Company's target in these two Permits is oil. Significantly, a number of wells in the Bass Basin have either found reservoired oil or encountered strong live oil indications.

The Permits are not subject to Native Title claims.

Budgeted Expenditure – T/37P

Year of Term of Permit	Summary Work Program	Exoil's 35% Share of	
		Budgeted Expenditure* A$	Indicative Expenditure* A$
		2008/2009	**2009/2010**
Year 4	Geological & Geophysical Studies	40,000	55,000
Year 5	Drill One Well		NIL
TOTAL BUDGETED EXPENDITURE 2008/2009		40,000	
TOTAL INDICATIVE EXPENDITURE 2009/2010			55,000
* **ASSUMPTIONS:** That the Year 5 well obligation is farmed out or rolled into Year 6 or an election is made not to drill.			

Budgeted Expenditure – T/38P

Year of Term of Permit	Summary Work Program	Exoil's 35% Share of	
		Budgeted Expenditure* A$	Indicative Expenditure* A$
		2008/2009	**2009/2010**
Year 3	Drill Spikey Beach 1 Well	NIL	NIL
	Seismic Interpretation	50,000	55,000
Year 4	Geological & Geophysical Studies		105,000
TOTAL BUDGETED EXPENDITURE 2008/2009		50,000	
TOTAL INDICATIVE EXPENDITURE 2009/2010			160,000
* **ASSUMPTIONS:** That Beach will drill the Spikey Beach-1 well as per its farmin obligation.			

BROWSE BASIN: OFFSHORE WESTERN AUSTRALIA
29.75% INTEREST
OPERATOR: EXOIL LIMITED

Exoil, through its wholly owned subsidiary, Hawkestone Oil Pty Ltd, holds a 35% interest in three contiguous Permits (WA-332-P, WA-333-P and WA-342-P) operated by the Browse Joint Venture.

The Browse Joint Venture consists of:

Hawkestone Oil Pty Ltd	29.75%	
Batavia Oil & Gas Pty Ltd	29.75%	
Alpha Oil & Natural Gas Pty Ltd	17.00%	
Gascorp Australia Pty Ltd	15.00%	(earning pursuant to farmin)
Goldsborough Energy Pty Ltd	8.50%	

Figure 4 below shows the location of WA-332-P, WA-333-P and WA-342-P. For a geological description of WA-332-P, WA-333-P and WA-342-P see both the Martin Report and the RPS Energy Report in Section 7.

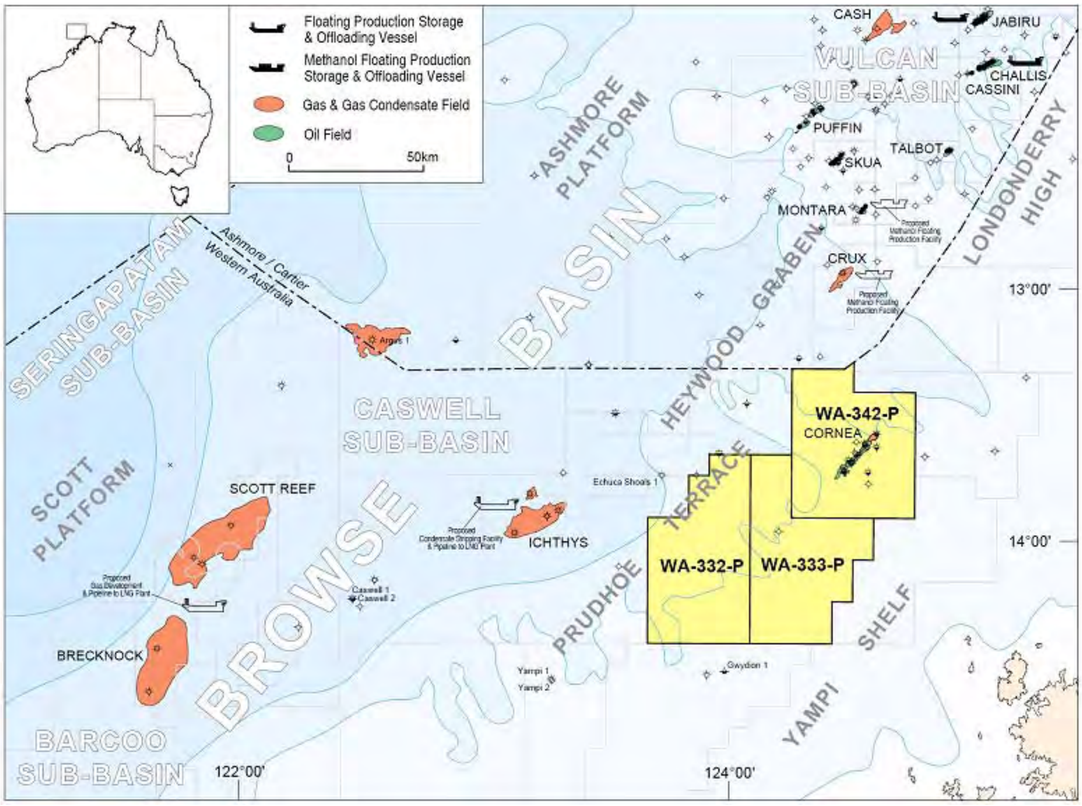

Figure 4. showing location of WA-332-P, WA-333-P and WA-342-P in Northern Browse Basin

The Browse Joint Venture previously acquired the Braveheart 2D seismic program over WA-332-P and WA-333-P and has obtained available open file reports and basic 2D and 3D seismic data acquired by previous explorers. This includes 2,000 km² of high quality 3D seismic over WA-342-P, known as the Cornea 3D survey, which is held by the Browse Joint Venture. Approximately 1,000 km^2 of this data has been entirely reprocessed. The data sets have been integrated with the acquisition and processing of the Braveheart 2D seismic survey to infill the existing grid of data, with lead specific coverage in some parts of WA-332-P and WA-333-P.

Amplitude Versus Offset ("AVO") studies over the Braveheart Prospect, which straddles WA-332-P and WA-333-P, have provided a drilling target for this Prospect. The Joint Venture next plans to acquire up to 770 line kms of new infill 2D seismic in Q4 2008 across WA-332-P and part of WA-333-P. The Joint Venture has farmed out this obligation to acquire the new 2D seismic to Gascorp Australia Pty Ltd. The terms of this arrangement are provided in Sections 10.1.15 to 10.1.17 inclusive.

The Joint Venture has committed to drilling the Braveheart-1 well in WA-333-P in 2009 by, in conjunction with other explorers, securing the services of the semi-submersible "Songa Venus" rig (see Section 10.1.13). The Joint Venture presently plans to farm out the obligations to drill the Braveheart-1 well.

The Permits are not subject to Native Title claims.

Budgeted Expenditure – WA-332-P

Year of Term of Permit	Summary Work Program	Exoil's 29.75% Share of	
		Budgeted Expenditure A$	Indicative Expenditure A$
		2008/2009	2009/2010
Year 5	Drill One Well	NIL	
	Acquire 400 kms of 2D Seismic	NIL	NIL
Year 6	Office Studies		100,000
TOTAL BUDGETED EXPENDITURE 2008/2009		NIL	
TOTAL INDICATIVE EXPENDITURE 2009/2010			100,000
* **ASSUMPTIONS:** That the Braveheart-1 well obligation is farmed out. That the 400 kms of 2D seismic due in Year 6 is acquired in Year 5 and the obligation is farmed out.			

Budgeted Expenditure – WA-333-P

Year of Term of Permit	Summary Work Program	Exoil's 29.75% Share of	
		Budgeted Expenditure* A$	Indicative Expenditure* A$
		2008/2009	2009/2010
Year 5	Drill Braveheart 1 Well	NIL	
	Acquire 400 kms of 2D Seismic	NIL	NIL
Year 6	Office Studies		100,000
TOTAL BUDGETED EXPENDITURE 2008/2009		NIL	
TOTAL INDICATIVE EXPENDITURE 2009/2010			100,000
* **ASSUMPTIONS:** That the Braveheart-1 well obligation is farmed out. That the 400 kms of 2D seismic due in Year 6 is acquired in Year 5 and the obligation is farmed out.			

Budgeted Expenditure – WA-342-P

Year of Term of Permit	Summary Work Program	Exoil's 29.75% Share of	
		Budgeted Expenditure* A$	Indicative Expenditure* A$
		2008/2009	2009/2010
Year 5	Geotechnical Studies	10,000	25,000
Year 6	Drill One Well		NIL
TOTAL BUDGETED EXPENDITURE 2008/2009		10,000	
TOTAL INDICATIVE EXPENDITURE 2009/2010			25,000
* **ASSUMPTIONS:** That the Joint Venture completes the proposed program of Geotechnical Studies in Year 5, followed by a well in Year 6. That the Year 6 well will be farmed out or an election is made not to drill. The Company does not plan to contribute to drilling a well in WA-342-P.			

EPP34 OTWAY BASIN: OFFSHORE SOUTH AUSTRALIA
15% INTEREST
OPERATOR: EXOIL LIMITED

The EPP 34 Joint Venture consists of:

Exoil Limited	15%
Moby Oil & Gas Limited	20%
National Energy Pty Ltd	15%
United Oil & Gas Pty Ltd	30%
Gascorp Australia Pty Ltd	10%
National Gas Australia Pty Ltd	10%

Figure 5 below shows the location of EPP 34 (plus EPP 35 and EPP 36 referred to below). For a geological description of EPP 34, EPP 35 and EPP 36 see the Independent Consultant Geologist's Report in Section 7.

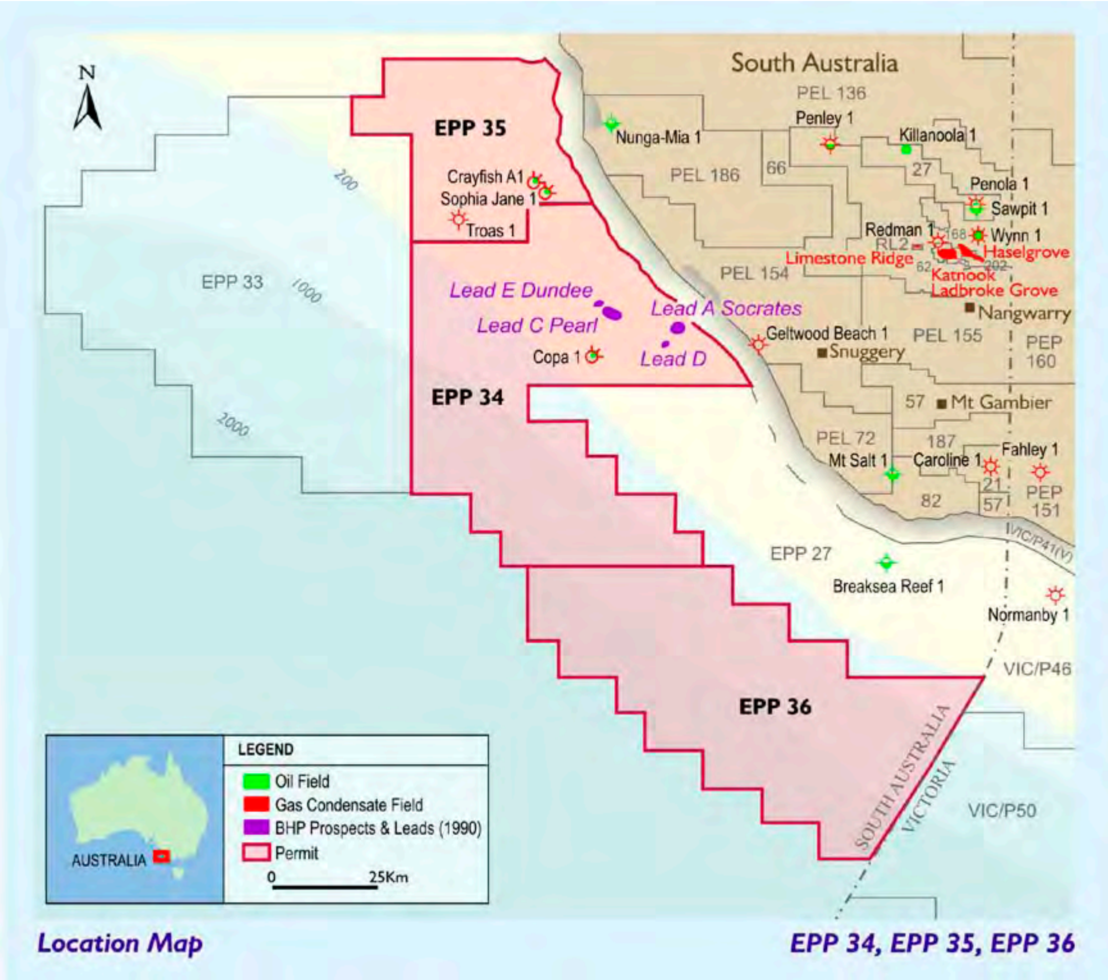

Figure 5: EPP 34, EPP 35 & EPP 36 location map in the Otway Basin, South Australia, showing structural elements and well control.

The Trocopa seismic survey of 1,100 kms of new 2D data was acquired in EPP34 during the quarter ended 30 June 2008. Reprocessing of more than 1,500 kms of old seismic data held over the Permit is also planned simultaneously with the processing of the seismic data from the Trocopa survey. Interpretation is being focused on the northern shelfal section of the block, targeting the Early Cretaceous Pretty Hill Sandstone.

The Trocopa seismic survey will provide extensive modern 2D coverage in the northern part of the Permit and is expected to open up the Joint Venture to the possibility of a series of gas plays.

The Permit is not subject to Native Title claims

Budgeted Expenditure – EPP34

Year of Term of Permit	Summary Work Program	Exoil's 15% Share of Budgeted Expenditure* A$	Exoil's 15% Share of Indicative Expenditure* A$
		2008/2009	**2009/2010**
Year 4	Interpretation & Mapping	30,000	
Year 5	Drill One Well		NIL
TOTAL BUDGETED EXPENDITURE 2008/2009		30,000	
TOTAL INDICATIVE EXPENDITURE 2009/2010			NIL
* **ASSUMPTIONS:** That the Year 5 well obligation is either farmed out or rolled into Year 6 or an election is made not to drill.			

EPP35 OTWAY BASIN: OFFSHORE SOUTH AUSTRALIA
30% INTEREST
OPERATOR: EXOIL LIMITED

The EPP35 (Troas) Joint Venture consists of:

Exoil Limited	30%
Gascorp Australia Pty Ltd	30%
National Energy Pty Ltd	20%
Moby Oil & Gas Limited	20%

Figure 5 above shows the location of EPP35. For a geological description of EPP35 see the Independent Consultant Geologist's Report in Section 7.

EPP35 contains the Troas gas accumulation where gas indications in the Troas-1 well were noted over more than 1,000 metres of sedimentary section. The Permit therefore has a proven hydrocarbon system in place. The Joint Venture's focus has been on the Troas Deep Prospect and it currently plans to shoot a 325 km² 3D seismic grid over the Troas Deep complex. This is budgeted for 2009/2010, with the Joint Venture planning to farm out the cost of this survey.

The Permit is endowed with a wide range of potential prospects, with 'fair to good' seismic and well data coverage.

The Permit is located approximately 120 km from the gas pipeline to Adelaide. The Permit is not subject to Native Title claim.

Budgeted Expenditure – EPP35

Year of Term of Permit	Summary Work Program	Exoil's 30% Share of Budgeted Expenditure* A$	Exoil's 30% Share of Indicative Expenditure* A$
		2008/2009	**2009/2010**
Year 3	Geological & Geophysical Studies Carry Out 325 km² 3D Seismic Survey	7,500 NIL	 Nil
Year 4	Processing Interpretation		100,000
TOTAL BUDGETED EXPENDITURE 2008/2009		7,500	
TOTAL INDICATIVE EXPENDITURE 2009/2010			100,000
* **ASSUMPTIONS:** That the Company's share of the Permit obligation to acquire 325 km² of 3D seismic is met by a farminee.			

EPP36 OTWAY BASIN: OFFSHORE SOUTH AUSTRALIA
30% INTEREST
OPERATOR: EXOIL LIMITED

The EPP36 Joint Venture consists of:

Exoil Limited	30%
Gascorp Australia Pty Ltd	30%
National Energy Pty Ltd	20%
Moby Oil & Gas Limited	20%

Figure 5 above shows the location of EPP36. For a geological description of EPP36 see the Independent Consultant Geologist's Report in Section 7.

EPP36 is a deep water area, parallel to the Morum Sub-basin. It is thought to have excellent reservoir potential for stacked plays in thick Upper Cretaceous section.

Due to its proximity to the Morum Sub-basin, EPP 36 is postulated to have scope for marine influenced source rock in deep water.

There is an obligation for the 3rd budget year to acquire 1,100 kms of 2D seismic that is planned to be met by a farminee.

The Permit is not subject to Native Title claims

Budgeted Expenditure – EPP36

Year of Term of Permits	**Summary Work Program**	**Exoil's 30% Share of**	
		Budgeted Expenditure* A$	**Indicative Expenditure* A$**
		2008/2009	**2009/2010**
Year 3	Geological & Geophysical Studies Acquire 1,100 kms of 2D Seismic	5,000 NIL	5,000 NIL
Year 4	Seismic Processing & Interpretation		50,000
TOTAL BUDGETED EXPENDITURE 2008/2009		5,000	
TOTAL INDICATIVE EXPENDITURE 2009/2010			55,000
* **ASSUMPTIONS:** That the Company's share of the obligation to acquire 1,100 kms of 2D seismic is met by a farminee.			

VIC/P61 OTWAY BASIN: OFFSHORE VICTORIA
30% INTEREST
OPERATOR: EXOIL LIMITED

The Vic/P61 Joint Venture consists of:

Exoil Limited	30%	
Gascorp Australia Pty Ltd	30%	
Moby Oil & Gas Ltd	20%	(earning pursuant to farmin)
Southern Energy Pty Ltd	20% Strata	(holds 10% on behalf of each of Octanex NL and Resources NL)

Figure 6 below shows the location of Vic/P61. For a geological description of Vic/P61 see the Independent Consultant Geologist's Report in Section 7.

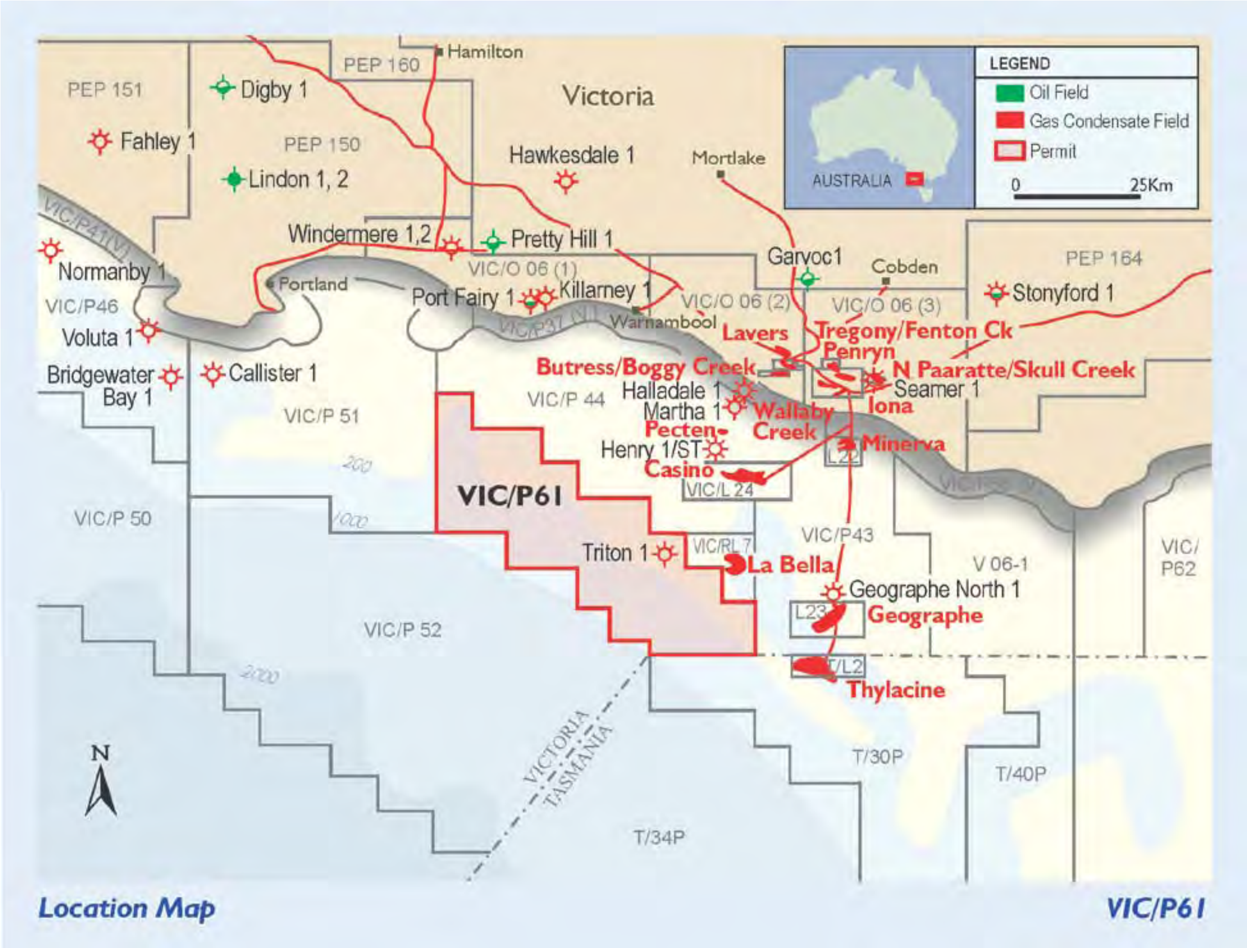

Figure 6 . VIC/P61 location map in the Otway Basin, Victoria, showing prospects and leads, well control and nearby discoveries.

Vic/P61 is in the offshore Otway Basin some 50-60 kilometres southwest of Port Campbell. The area comprises 30 graticular blocks covering approximately 1,874 kms² and is situated on the shelf margin of the Basin where water depths vary between 80-500m. The Permit's eastern boundary is close to gas discoveries and new developments at Minerva, Geographe, Thylacine and Casino. Seismic surveys over the Permit are entirely 2D and vary in quality and extent. The Joint Venture plans to acquire up to 1,000 line kms of new 2D seismic.

The Permit is not subject to Native Title claim.

Budgeted Expenditure – VIC/P61

Year of Term of Permit	Summary Work Program	Exoil's 30% Share of	
		Budgeted Expenditure* A$	Indicative Expenditure* A$
		2008/2009	2009/2010
Year 2	Geological & Geophysical Studies Acquire 1,000 kms of 2D Seismic	10,000 Nil	10,000 Nil
Year 3	Carry Out 450 km² 3D Seismic Survey	Nil	Nil
TOTAL BUDGETED EXPENDITURE 2008/2009		10,000	
TOTAL INDICATIVE EXPENDITURE 2009/2010			10,000
* **ASSUMPTIONS:**	That the Company farms out the cost of all year 2 and year 3 obligations. If the Company is unable to farm these out it will be required to meet them or surrender the Permit. To meet these obligations the Company would need to raise capital. Indicative cost for the Company's share of the 2D seismic survey is $600,000, for the 3D seismic survey $2,700,000 and for the well (in Year 5) $5,400,000.		

WA-359-P DAMPIER BASIN / RANKIN TREND: OFFSHORE WESTERN AUSTRALIA
20% INTEREST
OPERATOR: MEO AUSTRALIA LIMITED

Participants in the Permit are:

North West Shelf Exploration Pty Ltd (MEO Australia Ltd Subsidiary)	60%
Exoil Limited	20%
Cue Exploration Pty Ltd (Cue Energy Resources Ltd Subsidiary)	20%

Figure 7 below shows the location of WA-359-P. For a geological description of WA-359-P see the Independent Consultant Geologist's Report in Section 7.

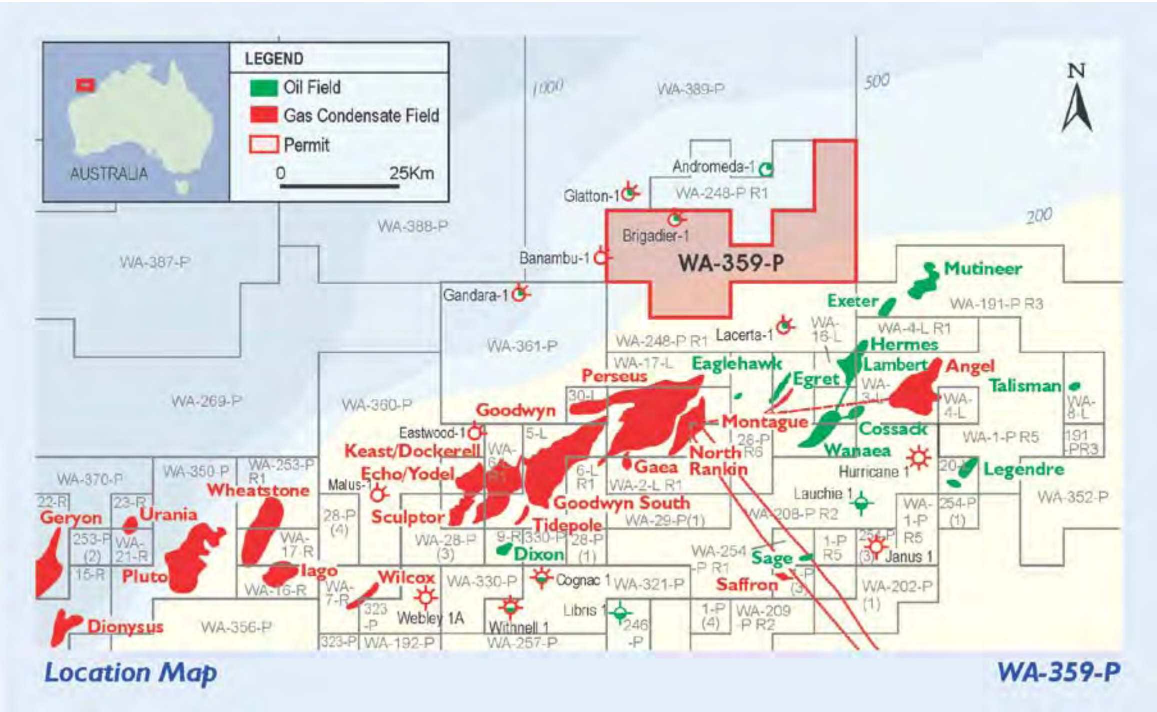

Figure 7 showing location of the location of WA-359-P in Northern Carnarvon Basin

WA-359-P, in the Dampier Basin offshore from Western Australia, covers an area of approximately 1,200 kms² in water depths of less than 500m.

A small 2D seismic survey was recently acquired in the Permit.

A wholly owned subsidiary of MEO Australia Limited ("MEO") farmed into Exoil and Cue's 50% interests in the Permit and will earn a 60% interest by meeting the year-3 commitment to acquire 250 line kms of new 2D seismic (now completed) and by funding 90% of the cost of drilling the first exploration well in the Permit. By 31 December 2008, MEO must make an election to drill a well in WA-359-P or withdraw from the Permit. MEO has announced that it has granted Resource Development International Ltd ("RDI") an option to earn a 35% interest in the Permit. The proposed farmout by MEO to RDI does not affect the Company's interest and does not relieve MEO of its obligations to elect to drill a well within the prescribed period.

As part of the farmout to MEO, the Company is required to make an election of whether to fund 5% its 20% interest in the well - that election must be made within 90 days of the date that MEO makes its election to drill the well in WA-359-P. If the Company elects not to fund that 5% cost, its interest dilutes to 15% and that 15% is then fully carried through 100% of the cost of the well.

The Permit is not subject to Native Title claim.

Budgeted Expenditure – WA-359-P

Year of Term of Permit	**Summary Work Program**	**Exoil's 20% Share of**	
		Budgeted Expenditure* A$	**Indicative Expenditure* A$**
		2008/2009	**2009/2010**
Year 4	Seismic Interpretation	NIL	
Year 5	Drill One Well		NIL
TOTAL BUDGETED EXPENDITURE 2008/2009		NIL	
TOTAL INDICATIVE EXPENDITURE 2009/2010			NIL
* **ASSUMPTIONS:** That the Company's share of obligations to carry out office studies and to drill a well are met by MEO as farminee.			

SECTION 5: CAPITAL STRUCTURE AND FINANCIAL INFORMATION

CAPITAL STRUCTURE

The Company presently has on issue a total of 101,550,526 fully paid ordinary shares (“Shares”) and 4,300,000 options to acquire ordinary shares, of which 1,950,000 of these options are exercisable at 15 cents and 1,350,000 are exercisable at 20 cents.

The rights and liabilities attaching to the Shares and options are as set out in Section 10.2.

The capital of the Company, as set out in Section 9 in the financial statements of the Company as at 30 June 2008, show a total of 50,775,263 shares on issue at that date, together with a total of 1,850,000 options over unissued shares with an expiry date of 31 December 2009.

On 3 September 2008, a resolution was passed in general meeting subdividing each issued share in the Company into two ordinary shares. The effect of the resolution was to increase the number of shares on issue to 101,550,526 fully paid ordinary shares and 3,700,000 options. By operation of the terms of the 1,850,000 options, each option also subdivided into 2 options on the same terms, except that the exercise price of each option was reduced by 50%, reflecting the subdivision of the shares. The aggregate exercise price of all the options did not change. The increase in the number of options over the 3,700,000 resulting from subdivision reflects the position that 600,000 options exercisable at $0.20 cents were granted to Mr J G Tuohy subsequent to 3 September 2008 as part of the terms and conditions of his appointment as Company Secretary: replacing Mr D B Hill.

FINANCIAL STATEMENTS

Audited financial statements of the Company as at 30 June 2008 are contained in Section 9. Proposing Investors should read those audited financial statements to gain a full understanding of the financial position of the Company as at the date thereof.

Set out below are summaries of the financial position of the Company both as 30 June 2008 (being the date of the last audited balance sheets of the Company) and as at 30 September 2008 (based on unaudited management accounts as at that date). In both cases the accounts are presented for the Company and, separately, on a consolidated basis.

Save that the Bazzard 1 was drilled and abandoned; there have been no material changes in the financial position of the Company subsequent to 30 June 2008 which are not disclosed herein.

Balance Sheets
Exoil Limited

	Consolidated		Company	
	Unaudited Management Accounts 30/09/2008	Audited Accounts 30/06/2008	Unaudited Management Accounts 30/09/2008	Audited Accounts 30/06/2008
	$		$	$
CURRENT ASSETS				
Cash and cash equivalents	**735,226**	970,987	**727,190**	974,743
Trade and other receivables	**128,479**	299,381	**112,529**	289,140
Total current assets	**863,705**	1,270,368	**839,719**	1,263,883
NON-CURRENT ASSETS				
Exploration and evaluation assets	**3,898,886**	3,732,656	**2,892,627**	2,852,385
Property, plant and equipment	**74,097**	78,033	**74,097**	78,033
Other financial assets	**25,067**	25,067	**1,111,293**	1,069,293
Total non-current assets	**3,998,050**	3,835,756	**4,078,017**	3,999,711
TOTAL ASSETS	**4,861,755**	5,106,124	**4,917,736**	5,263,594
CURRENT LIABILITIES				
Trade and other payables	**351,094**	528,433	**215,833**	494,506
Total current liabilities	**351,094**	528,433	**215,833**	494,506
NON-CURRENT LIABILITIES				
Deferred tax liabilities	**561,981**	573,861	**561,981**	573,861
Total non-current liabilities	**561,981**	573,861	**561,981**	573,861
TOTAL LIABILITIES	**913,075**	1,102,294	**777,814**	1,068,367
NET ASSETS	**3,948,680**	4,003,830	**4,139,922**	4,195,227
EQUITY				
Contributed equity	**2,959,055**	2,959,055	**2,959,055**	2,959,055
Reserves	**81,277**	81,277	**81,277**	81,277
Retained earnings	**908,349**	963,498	**1,099,590**	1,154,895
Total Equity	**3,948,680**	4,003,830	**4,139,921**	4,195,227

BUDGET MATTERS AND EXPENDITURE

The following table shows the proposed use of available funds at 30 June 2008 during the initial two year period from the date hereof. The period 2008/2009 is for a 14 months from 1 May 2008 to 30 June 2009 and the period 2009/2010 is for the following 12 months to 30 June 2010.

It is difficult to budget for the costs of exploration with any certainty. Any estimate of the cost of exploration activity is based upon best estimated costings prepared by the Operator of each Joint Venture, but it is not possible to fix costs absolutely. Exploration expenditure rates are, for the most part, fixed on a daily basis. Project costs are highly sensitive to operational risks, as well as to weather and environmental downtime.

In reviewing the budgeted expenditures set out in the Source and Application of Funds statement below, Proposing Investors should have regard to the budgets set out in relation to each Permit detailed in Section 4 and the assumptions included in each one of those budgets. For convenience, specific assumptions relating to each individual Permit are set out beneath the statement of budgeted expenditure in relation thereto.

The Directors are satisfied that, with existing funds, the Company will have sufficient working capital to meet its stated objectives for the period ended 30 June 2009, according to its budgeted expenditures during that period.

SOURCE AND APPLICATION OF FUNDS	**2008/2009**	**2009/2010**
Available Funds as at 30 June 2008	1,270,368	N/A
Accounts Payable as at 30 April 2008	(528,433)	N/A
Available Funds 1 July 2009	N/A	**344,435**
Funds from Stuart Petroleum re farmin to Vic/P53	798,600	0
Proceeds from anticipated Share Issue (2009/2010)	N/A	1,500,000
Total Available Funds	**1,540,535**	**1,844,435**
Exploration Expenditure		
Vic/P53	0	33,333
Vic/P45	10,000	100,000
T/37P	40,000	55,000
T/38P	50,000	160,000
WA-332-P	0	100,000
WA-333-P	0	100,000
WA-342-P	10,000	25,000
EPP34	30,000	0
EPP35	7,500	100,000
EPP36	5,000	55,000
Vic/P61	10,000	10,000
WA-359-P	0	0
Other Expenditure		
Capital Payment to Cue Petroleum Pty Ltd (see Section 10.1.3)	798,600	0
Administration and Corporate		
Administration	90,000	120,000
Listing Costs	50,000	0
Directors Fees	60,000	60,000
Other Corporate Expenses	35,000	75,000
Total Expenditure	**1,196,100**	**993,333**
Unallocated Working Capital at End of Year	**344,435**	**851,102**

The Company's ability to meet budgeted expenditures during 2010 and later years will depend on the results of activities in 2009, as well as on its ability to raise capital, whether from a subsequent issue of shares, from the exercise of existing options or from farm outs and other means. The use of funds statement set out above contemplates that a capital raising of approximately $1,500,000 is proposed in the 2009/2010 year. The Directors consider it reasonable to anticipate that, if the Company achieves any significant level of success in its operations, that the existing options would be exercised.

Actual use of funds may differ from budgeted use of funds based on the outcomes from the Company's exploration activities in relation to any project, which may vary from present expectations, and the requirement to obtain various regulatory and other approvals in relation thereto.

The Directors will continually review the exploration strategy as results are obtained or events transpire and will review projects and allocate funds to maximise Shareholder value. The above Source and Application of Funds statement is the current proposed use of funds, but is subject to modification at the discretion of the Board.

SECTION 6: DIRECTORS AND MANAGEMENT

GENERAL

The Company is presently primarily managed by its Directors and the Company Secretary, whose details are as set out below.

DIRECTORS AND COMPANY SECRETARY

The current Directors and Company Secretary are:

James M D Willis LLM (Hons) Dip Acc
Chairman
(Executive Director)

Until his resignation in 2007, Mr Willis had been a partner in the leading New Zealand law firm of Bell Gully for 25 years. His practice speciality was in the upstream oil and gas area, particularly relating to issues concerning gas contracting and the development of oil and gas reserves, joint ventures and upstream petroleum related acquisitions. He has acted for the leading participants in the upstream petroleum industry in New Zealand.

In 2007 Mr Willis relocated to Australia to take up a management role with the group of companies controlled by Mr Albers and his associates (including Exoil) and is now a fulltime executive director of companies in that group.

Mr Willis was until recently a director of MEO Australia Limited, a position he had held for 10 years during a crucial period of its growth. With Mr Albers he was co-founder and later a director of Southern Petroleum, a successful New Zealand explorer now wholly owned by Shell.

Mr Willis is a director of Gascorp Australia Pty Ltd, a company controlled by Mr Albers and interests associated with him and which is a joint venturer in various of the Company's permits as disclosed herein. Mr Willis has been a Director of the Company since 2004.

Mr E Geoffrey Albers LLB
(Executive Director)

Mr Albers has over 30 years experience as a director and administrator in corporate law, petroleum exploration and resource sector investment. He is a law graduate of the University of Melbourne and, after being admitted in 1969 as a Solicitor of the Supreme Court of Victoria, practiced commercial and corporate law in Victoria until 2001.

In 1978 Mr Albers first became involved in oil exploration. At that time companies associated with him applied for and were awarded exploration permits in the offshore Bass Basin. Exploration in one of these permits, T/14P, led directly to the discovery of the Yolla Gas/Condensate Field which is now being produced by Origen Energy Limited and others.

In the early 1980's Mr Albers formed Cue Energy Resources Limited ("Cue Energy") in New Zealand, of which he remains a Director and which has a significant interest in the Maari oilfield development, the unitised S E Gobe oilfield and the Oyong oil and gas development in offshore Indonesia. Mr Albers is a director of, and substantial shareholder in, Cue Energy. See Cue Energy's website www.cuenrg.com.au

Mr Albers was a founder of MEO Australia Limited (ASX Code: MEO) and is a former director and shareholder of that company. MEO is now pursuing the development of a $2 billion gas processing plant on Tassie Shoal in the Timor Sea, 300kms north-west of Darwin. Mr Albers also founded Bass Strait Oil Company Ltd ("BSOC") (ASX Code: BAS) which has developed a portfolio of interests in the offshore Gippsland Basin and is a niche explorer in that basin. Mr Albers is a director of, and substantial shareholder in, BSOC. See BSOC's website www.bassoil.com.au. In 2004 Mr Albers was instrumental in the formation of Moby Oil & Gas Ltd (ASX Code: MOG) which has extensive interests in various permits in Bass Strait. Mr Albers is a director of, and substantial shareholder in, Moby Oil & Gas Ltd. See Moby's website www.moby.com.au

In 2002 and under Mr Albers' control, Octanex NL ("Octanex") and Strata Resources NL ("Strata") acquired interests in the Exmouth and Dampier areas of the North West Shelf, offshore Western Australia. Octanex is admitted to the Official List of NSX (NSX Code: OCT) and has been highly successful. See Octanex's website www.octanex.com.au. Mr Albers is a director of, and substantial shareholder in, each of Octanex and Strata.

Mrs Pamela J Albers
(Non- Executive Director)

Mrs Albers has more than 35 years of commercial experience, including co ownership and management of a significant primary production operation. She has a background in human resources, health & safety and in public relations.

Mrs Albers has been a director of a number of corporations, including public companies, over the last 15 years. She is a director of the NSX listed Octanex NL (NSX Code: OCT) and a substantial shareholder in that company. She is also a substantial shareholder in Exoil Limited.

Mr Graeme A Menzies LLB
(Non-Executive Director)

Mr Menzies is a solicitor practising in the area of commercial and company law. He graduated from Melbourne University in 1971 and qualified for admission to the degree of Master of Laws in 1975. He was admitted to practice in 1972. Since 1987 he has carried on practice as a sole practitioner under the name of Menzies & Partners. In the course of his legal practice, Mr Menzies has been involved in a wide range of activities including takeovers, litigation in respect thereof, numerous capital raisings and corporate reconstructions. He has been involved in the listing or relisting of a large number of public companies both industrial and mining.

Mr Menzies is a director of Gascorp Australia Pty Ltd, a company controlled by Mr Albers and interests associated with him and which is also a joint venturer in various of the Company's permits as disclosed herein. Mr Menzies is also a director of each of Moby Oil & Gas Limited (ASX Code: MOG), Octanex and Oil Basins Limited (ASX Code: OBL), all involved in exploration for oil and gas. Additionally, Mr Menzies is a director of Papyrus Australia Limited (ASX Code: PPY) and China Cattle Limited (ASX: Code CCL), as well as being a director of a number of other private and unlisted public companies.

Mr Menzies has generally acted as a non-executive director of exploration companies or technology companies.

Mr Menzies has a significant skill base which will be of considerable value to the Company in carrying out its activities.

Mr John (Jack) G Tuohy BCA, ACA
(Company Secretary)

For all but two years since 1986, Mr Tuohy has acted as Company Secretary to Public Listed companies in New Zealand. The first half of that period he spent in the oil and gas sector, initially administering three oil and gas exploration companies in which Messrs Albers and Willis were directors and which they had originally listed. He then acted for only one of them, Southern Petroleum, when it became a successful production company.

Following that period Mr Tuohy acted in a forensic accounting capacity in a multi party legal action, before returning to a secretarial position in the motor vehicle industry where he spent the last 10 years.

In these positions, Mr Tuohy has been involved in the various aspects of public and private company administration, especially as this relates to the oil and gas exploration sector and to public listed company activities, obligations and requirements. He recently relocated to Australia to take up the position of Company Secretary of a number of Mr Albers' and his associates group of companies, of which Exoil is one.

Mr Tuohy is a chartered accountant in New Zealand.

Proposing Investors are also referred to clauses in Sections 10.3.6 to 10.3.9 dealing with Directors' interests generally.

SECTION 7: INDEPENDENT CONSULTANT GEOLOGISTS' REPORTS

Michael J Martin
Petroleum Geological Advisor

8 Alness Street
APPLECROSS WA 6153
AUSTRALIA
Office Phone: 61 8 9364 8942
Office Fax: 61 8 9316 3141
Email: mjhmartin@ozemail.com.au

The Directors
Exoil Limited
Level 21
500 Collins Street
MELBOURNE Vic 3000
AUSTRALIA

Gentlemen,

RE: REPORT ON THE GEOLOGY AND EXPLORATION POTENTIAL OF PETROLEUM EXPLORATION INTERESTS

SUMMARY

Michael J Martin, Independent Consultant Geologist, was commissioned by Exoil Limited (ABN 40 005 572 798) (Exoil and the Company) to provide a Technical Report on the company's exploration assets in certain offshore basins of Australia. As a result the five attached reports and glossary, namely:-

- Section 1 – The Gippsland Basin Tenements;
- Section 2 – The Bass Basin Tenements;
- Section 3 – The Otway Basin Tenements;
- Section 4 – The Browse Basin Tenements;
- Section 5 – The Brigadier Rankin Trend Permit;
- Glossary,

have been prepared for inclusion in an Information Memorandum to be issued by Exoil Limited in support of an application for listing by that company on the stock market conducted by the National Stock Exchange Limited.

The author considers that the tenements are prospective for the entrapment of oil and gas, on the basis of results from previous exploration, examination of the available technical data, and recent exploration successes in each region.

The proposed budgets and past expenditures of the Company are consistent with its exploration objectives.

Exoil has a satisfactory and clearly defined exploration and expenditure programme which is reasonable having regard to its stated objectives; and that enough exploration has taken place in the recent past to justify the budgeted exploration and expenditure program.

In the author's opinion the proposed work programmes and budgets of the Company and its Joint Venturers reflect the exploration potential for oil and gas in the tenements and the potential for integration with nearby developments.

LIMITATIONS

The following report is based on information provided to M.J. Martin – Petroleum Geological Advisory, by Strat Trap Pty Ltd, other documents supplied by the Company and available published information. Discussions were held with staff of Strat Trap Pty Ltd, consultants to the Company, Geoff Geary – PetroConsult, consultants to the company and with Cue Energy Resources Ltd, a joint venturer with Exoil. The author has no reason to believe that any information has been withheld, but this does not imply that an audit has been made of the technical, legal or accounting records. The report has been prepared before all of the seismic data available in the permits has been completely integrated into the technical database.

QUALIFICATIONS

Michael J. Martin is a Perth based petroleum geologist with over 30 years of experience in the international petroleum industry and has provided technical services and management advice to the industry over the past ten years as an independent consultant.

Mr Martin began his professional career in Kuwait and later the western Mediterranean offshore oil fields of Spain, prior to joining the burgeoning North Sea oil boom in the early seventies. Following assignments in London with Atlantic Richfield and Cities service, he joined Getty Oil in their Perth, Western Australia office. After his departure from Getty, Mr Martin worked with the petroleum division of a major Australian Mining House. Lately he has been actively involved in exploring the Northwest Shelf hydrocarbon basins and other Southeast Asia basins as a consultant for numerous clients.

DECLARATION

The author has no pecuniary or other interest that could reasonably be regarded as being capable of affecting his ability to give an unbiased opinion in relation to the petroleum exploration assets of Exoil.

I, the undersigned, have given and not withdrawn my written consent to be named in such Information Memorandum as an independent consultant geologist to Exoil Limited in the form and context in which I am so named and, in addition, I have given and not withdrawn my written consent to the despatch of this with this independent report being included therein in the form and context in which it is so included and to references thereto (either express or by inference) being included in such Information Memorandum in the form and context in which they are so included.

Yours faithfully

M.J. MARTIN

21st October 2008

REPORT ON THE GEOLOGY AND EXPLORATION POTENTIAL

SECTION 1

THE GIPPSLAND BASIN TENEMENTS – Vic/P45 & Vic/P53

Exoil holds interests in two tenements, VIC/P45 and VIC/P53 (see Figure 1), located in the Gippsland Basin, offshore Victoria, which is situated in southeastern Australia some 200 kilometres east of Melbourne. The basin covers an area of 41,000 square kilometres with two thirds of the basin extending 200 kilometres offshore into Bass Strait.

The offshore Gippsland Basin is one of Australia's most prolific hydrocarbon provinces with initial proven reserves estimated at over 4 billion barrels (Bbbl) of oil and condensate and 10 trillion cubic feet (Tcf) of gas. Pipeline systems totaling some 4,000 kilometres bring produced hydrocarbons to production, storage and distribution facilities on-shore (Figure 1). Gas distribution infrastructure is well established with a network of pipelines transporting gas to markets in Victoria, New South Wales, South Australia and Tasmania.

History of Exploration in the Gippsland Basin

The Esso/BHP Petroleum consortium has dominated exploration and production activities in the offshore Gippsland Basin since 1965 following the discovery of the Barracouta Gas Field. Other gas fields such as Snapper and Marlin were discovered soon afterwards with production beginning from Marlin and Barracouta in 1969.

The first commercial oil discovery came in 1967 with the giant Kingfish Oil Field (1.2 billion barrels recoverable). Oil production was commissioned in 1970 and since then the Gippsland oil fields have dominated crude oil production in Australia. Production peaked at 450,000 bopd (annual average) in 1985. Since then, crude oil and condensate production has declined as reserves in the first generation fields diminished and the rate of new discoveries could not compensate for production decline. Production currently averages some 660 MMcfd of gas and 140,000 bbl of oil and gas liquids per day (annual averages).

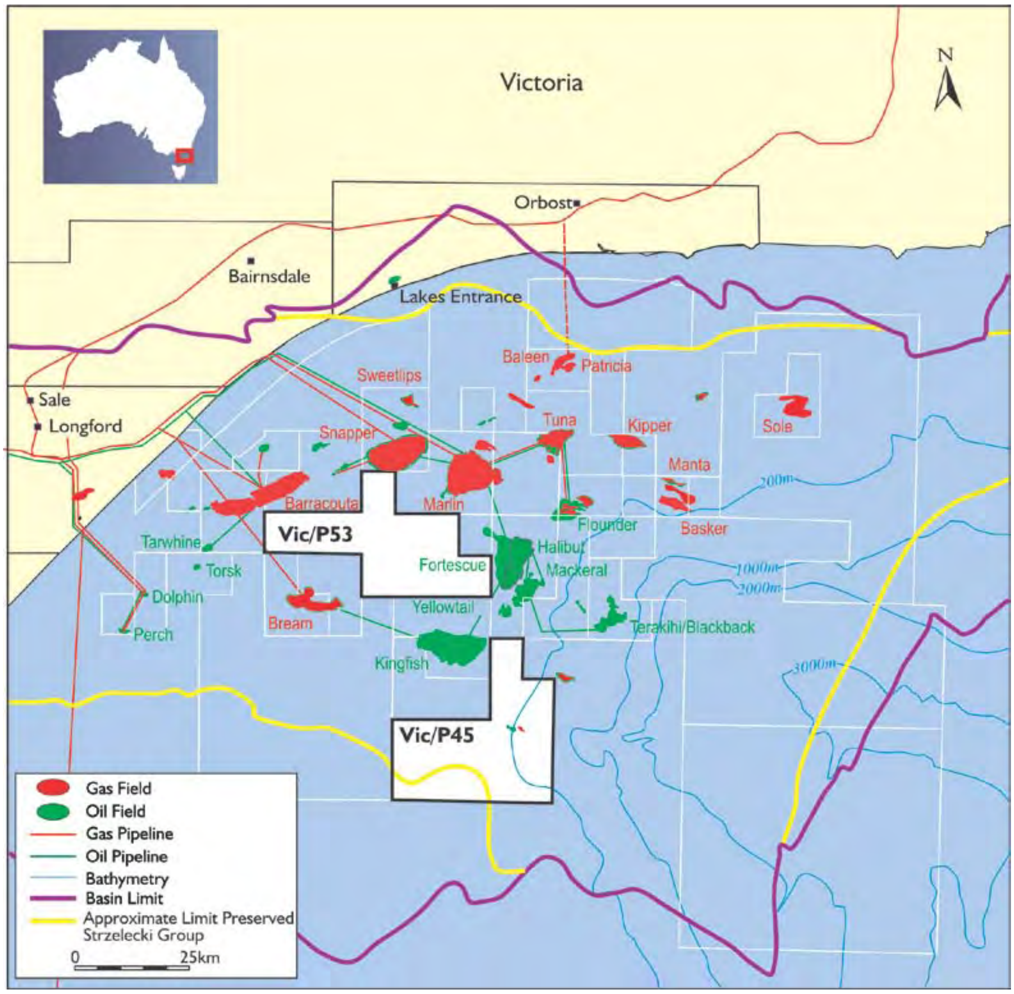

Figure 1. Oil and gas fields and pipeline infrastructure of the Gippsland Basin in relation to VIC/P45 and VIC/P53. (From Woollands & Wong, 2001)

Over 80,000 kilometres of 2D seismic data and twenty-five 3D surveys have been acquired in the onshore and offshore Gippsland Basin. Although the vast majority of 3D seismic surveys have been recorded over the major oil and gas fields for development purposes, recent acquisition has included large regional datasets acquired to assist exploration.

Some 230 exploration and appraisal wells have been drilled in the offshore part of the basin, and 160 exploration wells onshore. Drilling has resulted in 45 significant discoveries, all located offshore.

Regional Geology

The Gippsland Basin is an E–W trending rift to passive margin basin, one of a series of basins comprising the southern Australian margin rift system (Figure 2). These basins developed in response to breakup of Gondwanaland involving the separation of Antarctica from Australia and the development of the Southern Ocean. Basin evolution is recorded by dominantly siliciclastic sedimentary sequences from the Early Cretaceous to Eocene and carbonate sequences from the Early Oligocene to Recent. The stratigraphy of the Gippsland Basin is summarised in Figure 3.

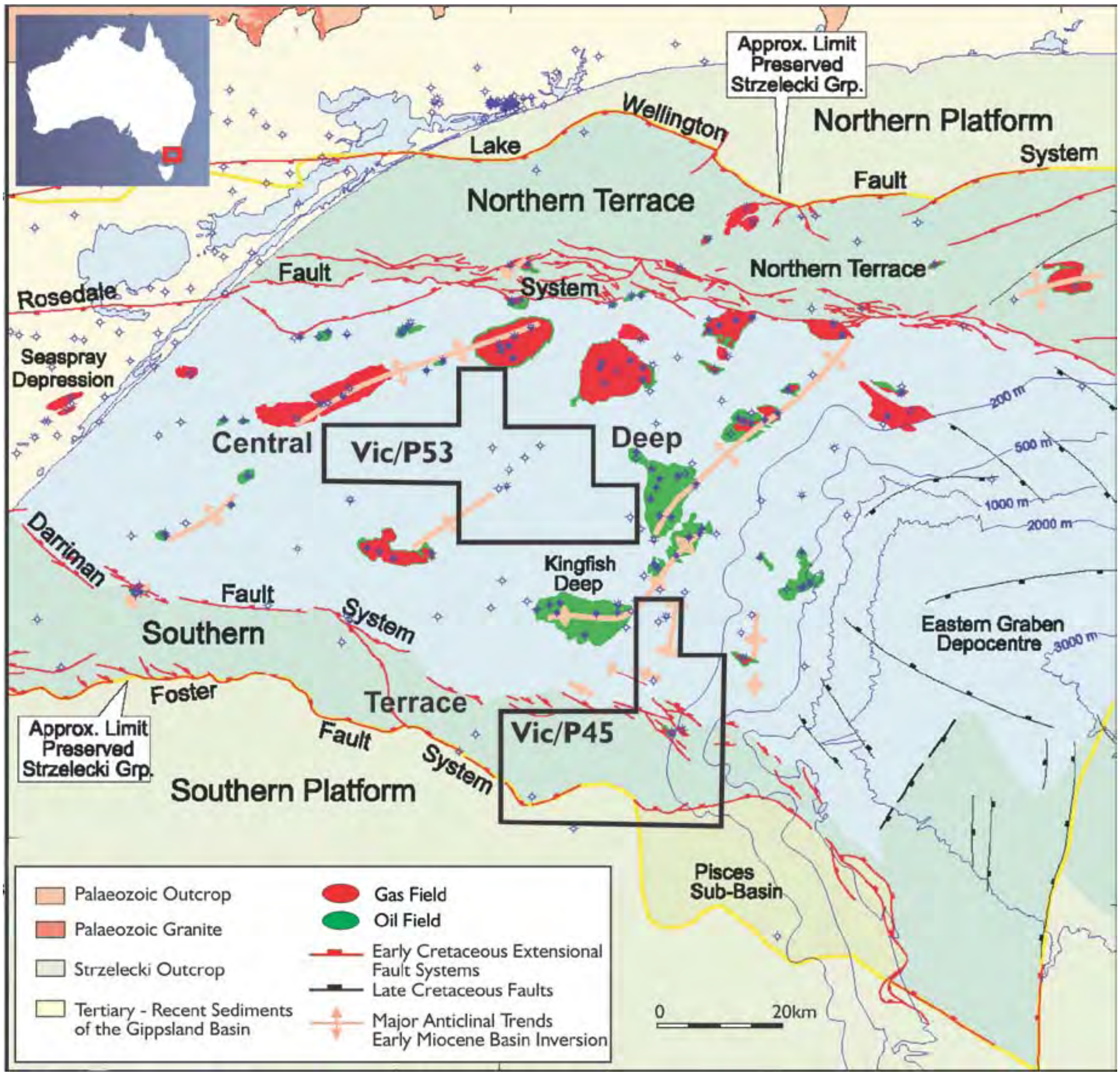

Figure 2. Structural elements and oil and gas fields of the Gippsland Basin. (After Woollands & Wong, 2001)

Tectonic Development

Rifting and continental detachment of Gondwanaland along the southern Australian margin began in the Late Jurassic, advancing rapidly in an easterly direction, progressively impacting the Great Australian Bight, Otway, Bass and Gippsland provinces.

The location of the Gippsland Basin and the adjacent Bass Basin at the junction between two Cretaceous rift systems, resulted in both basins experiencing multiple episodes of often complex deformation.

Initial Late Jurassic to Early Cretaceous rifting of the Gippsland Basin resulted in the formation of a major northeast-trending rift-valley graben complex infilled with thick volcano-clastic sediments of the Strzelecki Group. Deposition ceased in the mid-Cretaceous when compression caused widespread uplift and the genesis of the Otway Unconformity.

The basin was again impacted by extensional rifting early in the Late Cretaceous. Newly created major faults were oriented NW-SE (oblique to the earlier extensional event) with extension occurring parallel to the adjacent Tasman pull-apart motion. Lacustrine claystones of the Emperor Subgroup were deposited in deep, subsiding rift valleys with clastic wedges prograding over the faulted ramps from the basin margins. Deposition ended during a period of uplift associated with structural inversion in the mid-Cretaceous - late in the Turonian, which was marked by the Longtom Unconformity.

Rift-related extension was re-established early in the Santonian. Pronounced tectonism reactivated NW-SE faults accompanied by significant basin subsidence, mafic basaltic intrusion and volcanism. The Golden Beach Group comprising braided fluvial and deltaic sediments was deposited in the rapidly subsiding basin. The sequence records the influx of the first marine sediments into the basin. Volcanism peaked in the Late Campanian when much of the Golden Beach Group was covered by basaltic extrusive rocks.

The uppermost Cretaceous (Maastrichtian) Halibut Subgroup overlying the Seahorse Unconformity was deposited during a late syn-rift to post-rift thermal sag phase, whilst the Gippsland Basin continued to evolve as a failed arm of the Tasman rift system.

Sea-floor spreading in the Tasman Sea ceased in the Early Eocene. As the Central Deep continued to subside with deposition of the Cobia Subgroup, a pulse of NW-directed compression preferentially inverted the NE-oriented relay ramp segments of the normal fault systems, forming similarly oriented emergent anticlines across the central graben and northern margin regions (Figure 2). The eastern region of the central graben was also uplifted, imparting a westward-plunging regional tilt. Subaerial exposure of the rising section resulted in deep erosion, particularly focused across the eastern part of the basin and within the cores of emerging antiforms. This resulted in a prominent, often deeply incised unconformity (the Middle *M.diversus* Unconformity). Transgressive deposition of the Flounder Formation progressively filled the eroded channel region with initially sandy sediments, which gradually fined upwards into deepwater marine claystones.

Later pulses of Eocene to Early Oligocene compressional structuring in the central graben resulted in further incision (e.g. the Marlin and Top Latrobe unconformities) impacting the Flounder, Opah, Turrum and Gurnard formations. The Lakes Entrance Formation transgressively onlaps the structured surface of the Top Latrobe Group, with distal marine claystone and marl forming the ultimate regional topseal for top Latrobe structural traps.

Compression and structural growth peaked in the Middle Miocene with significant reverse faulting along the northern margin of the basin. Folding or tilting formed the major Latrobe Group structures which host most of the large oil and gas accumulations of the Gippsland Basin including the Kingfish, Barracouta, Snapper and Tuna fields.

Major submarine incisions during the mid to Late Miocene, are interpreted as offshore erosion/mass wasting events that may have been initiated by compressional reactivation. The channels so formed, were later infilled by prograding limestone and calcareous siltstone depositional wedges, often displaying high seismic velocities. These lithologies together comprise the Gippsland Limestone.

The basin continued to be affected by tectonic activity as documented by localised uplift during the Late Pliocene to Pleistocene, and as evidenced by Pliocene sediments on the Barracouta, Snapper and Marlin anticlines and in the area of Lakes Entrance. Ongoing tectonism to the present day is also episodically recorded by seismicity around the major basin bounding faults.

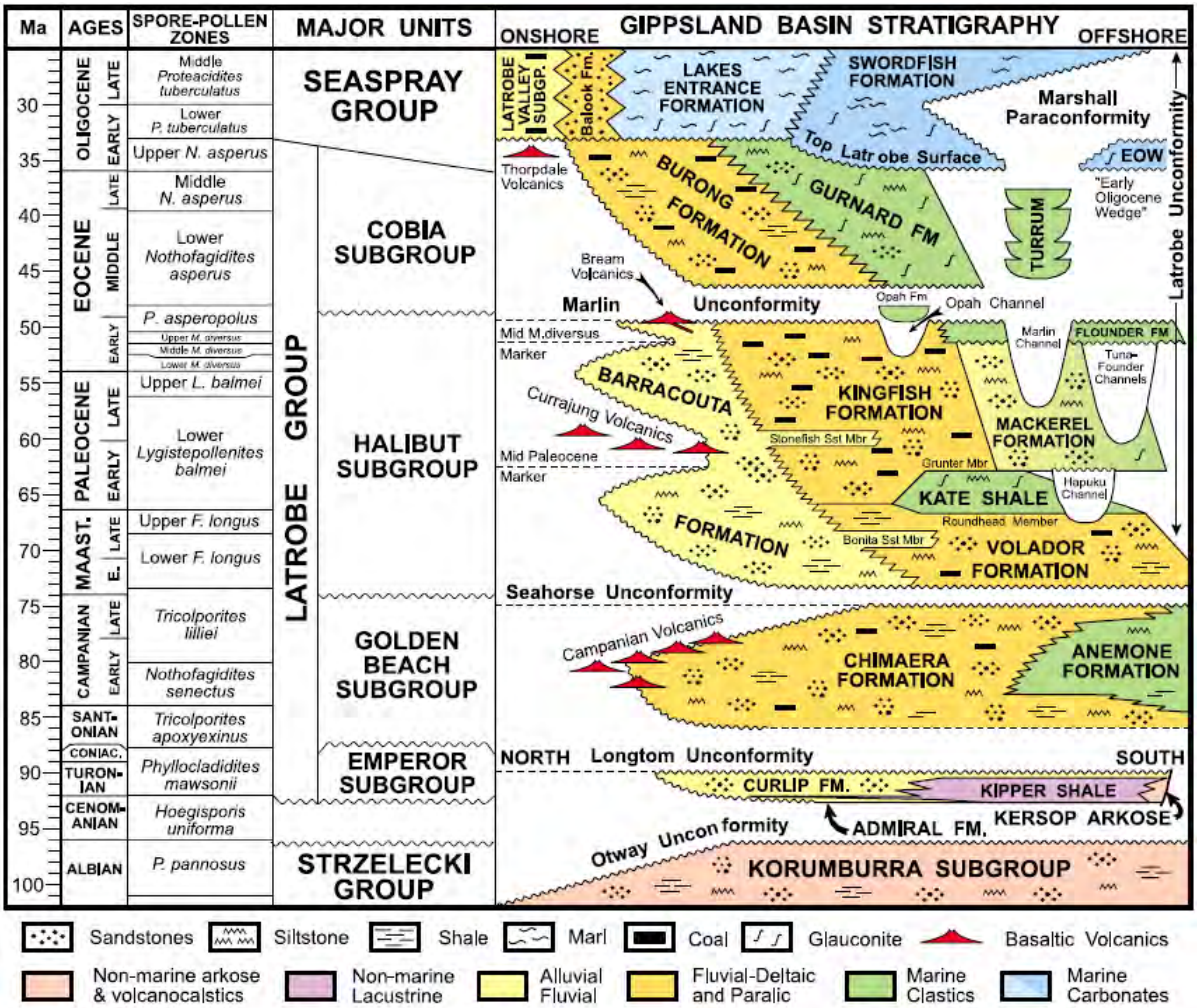

Figure 3. Stratigraphic units and unconformities within the Latrobe Group plotted against local palynological zones and timescale of Haq et al. (1987; 1988).

Stratigraphy

The sediments of the Gippsland Basin are sub-divided into three major groups: the Lower Cretaceous Strzelecki Group, the Upper Cretaceous to mid-Tertiary Latrobe Group, and the mid-Tertiary to Recent Seaspray Group (Figure 3).

The Strzelecki Group comprises interbedded lithic and volcano-clastic sandstones and mudstones with minor coals, a group which can be locally up to 3,000 metres thick; deposited in a non-marine, predominantly fluvial environment. The group is considered to have potential for hydrocarbon generation and accumulation, although reservoirs are characterised by low permeability.

The Latrobe Group unconformably overlies the sediments of the Strzelecki Group. It is dominated by coal-bearing fluvial and coastal plain siliciclastic sediments that occur in several, stacked depositional cycles. These layers can be sub-divided into four sub units: the Emperor, Golden Beach, Halibut and Cobia subgroups. Source, reservoir and seal lithologies occur throughout the Latrobe Group; a fact which helps to explain why the group hosts almost all of the oil and gas accumulations discovered so far in the Gippsland Basin.

The oldest unit of the Latrobe Group is the Emperor Subgroup, which comprises alluvial fan and braided stream sediments and contemporaneous lacustrine siltstones, claystones and minor sandstones; the sediments were deposited in basin margin and rift axis settings. The Emperor Subgroup is considered to have potential for hydrocarbon generation and accumulation, although reservoir potential is generally rated as only fair to poor.

The Golden Beach Subgroup unconformably overlies the Emperor Subgroup. It does not extend significantly beyond the Rosedale Fault System to the north, and the Foster Fault System to the south (Figure 2). The lower section of the subgroup comprises fluvial and deltaic sandstones and minor claystones, deposited along basin margins. Marine claystones provide evidence for the first basin-wide marine incursions into the southeastern part of the basin. The upper part of the subgroup contains widespread mafic basaltic intrusions and volcanics, which include locally extensive flows occasionally providing seals for underlying hydrocarbon-filled reservoirs (e.g. at the Kipper Field).

The Halibut Subgroup unconformably overlies the Golden Beach Subgroup. It comprises sandstones, mudstones and coal deposited in non-marine, estuarine to back-barrier environments. In the west this subgroup was deposited in lagoonal settings (the Barracouta Formation). To the east the Halibut Subgroup comprises coastal plain/delta front sediments (the Kingfish Formation), which pass into open marine shelfal to shelf slope settings (Mackerel Formation). In the central and western parts of the basin, the upper part of the Latrobe Group is sometimes referred to as the “Coarse Clastics” or “Latrobe Siliciclastics” a reservoir lithology which hosts approximately 90% of the hydrocarbons discovered so far in the basin.

The Mackerel Formation itself is diachronous and consists of stacked coastal to nearshore barrier complexes. To the southwest, the formation is represented by stacked turbidite sequences deposited in deep water on the shelf slope.

Compressional uplift in the Early Eocene, which was focused along the northern margin and the eastern part of the central graben, resulted in subaerial exposure of the rising coastal plain and marine sequences. In these regions, deep erosion resulted in an often deeply incised, channelised unconformity. The Flounder Formation progressively filled the eroded channels with sandy sediments, which were eventually replaced by deepwater marine claystones.

The Middle Eocene to Lower Oligocene Cobia Subgroup comprises the coal-bearing Burong Formation (lower coastal plain facies) and the shallow to open marine Gurnard Formation, a condensed section composed of fine to medium-grained glauconitic siliciclastic sediments. Also Included in the subgroup is the Turrum Formation, which consists of Mid-Eocene marine channel-fill sediments. Sealing lithologies are locally established within the Cobia subgroup, but it may act as both a waist zone or locally as a hydrocarbon reservoir. The combination of compressional structuring and consequent channel cutting and infill can create structural and stratigraphic traps; as found at the Fortescue, Halibut, Cobia and Mackerel fields.

Deposition of the Cobia Subgroup ended in the Early Oligocene, this cessation was coincident with compressional uplift and a marked decline in sediment supply. Large areas of the central basin bereft of sediment input, were left with starved condensed sections resulting in the development of what is traditionally known as the 'Latrobe Unconformity'.

Overlying the Latrobe Group is the Seaspray Group, which consists of marls and limestones, deposited in open-marine to shallow-marine environments. The Lakes Entrance Formation is a clay-rich, calcareous unit that forms a regional seal to the Latrobe Group. In parts of the basin, a seismic reflector known as the 'Mid-Miocene Marker' marks the top of the formation.

The overlying Gippsland Limestone is similar lithologically to the Lakes Entrance Formation but has a higher overall carbonate content. It contains zones of anomalously high and variable seismic velocities that produce distinctive seismically imaged two-way time pull-ups. Seismic velocity variations have enormous effects on the accurate depth mapping of target intervals in the Latrobe Group. The seismic velocity anomalies are generated by a complex system of Mid-Miocene channels that have eroded up to 300 metres into a sequence of calcareous sediments. These interfingering channels are filled with generally coarser carbonate characterised by higher velocities than the underlying carbonates, the channeled intervals show considerable lateral velocity variations.

Petroleum Potential

The Gippsland Basin is a world-class oil and gas-producing province. Historically, most exploration has focused on large structural traps with four-way-dip closures representing top Latrobe Group reservoirs that have been regionally sealed beneath thick Lakes Entrance Formation claystones and marls. The vast majority of wells in the basin do not penetrate far below the top Latrobe "Coarse Clastics". Historically, less attention has been focused on exploring underlying intra-Latrobe traps which are dependent upon intraformational seals.

With most of the prominent top Latrobe structures now tested, attention has now transferred to combined structural-stratigraphic plays in the intra-Latrobe and older Golden Beach subgroup sections, with the exploration effort aided by large regional 3D seismic surveys.

The deeper Golden Beach Subgroup is now recognised as an important exploration target in the basin. Discoveries at Basker-Manta and Kipper on the northern side of the basin, and at Archer and Anemone (within VIC/P45) on the southern basin margin, have demonstrated that a petroleum system has been operational within the Golden Beach Subgroup. This stratigraphic interval has only been intersected by 37 wells in the extant public domain data. A discovery in 2001 at East Pilchard-1, south of the Kipper Field, where 100 metres of gross gas pay was encountered, confirmed the intra-Latrobe / Golden Beach play in the northern margin and also reinforced the value of 3D seismic data in mapping and defining structures.

In areas where depth conversion has been problematic, such as in VIC/P53, Latrobe structures remain as valid and attractive targets. There is now a much better understanding of the anomalously high seismic velocities in the Gippsland Limestone which produce the distinctive two-way-time seismic pull-ups which have hindered accurate depth mapping of target intervals in the Latrobe Group. This understanding together with new depth conversion techniques used on 3D seismic such as forward modelling by ray tracing techniques, pre-stack depth migration (PSDM) or wave equation datum (WED) reprocessing, offers significant promise for better definition and depth conversion.

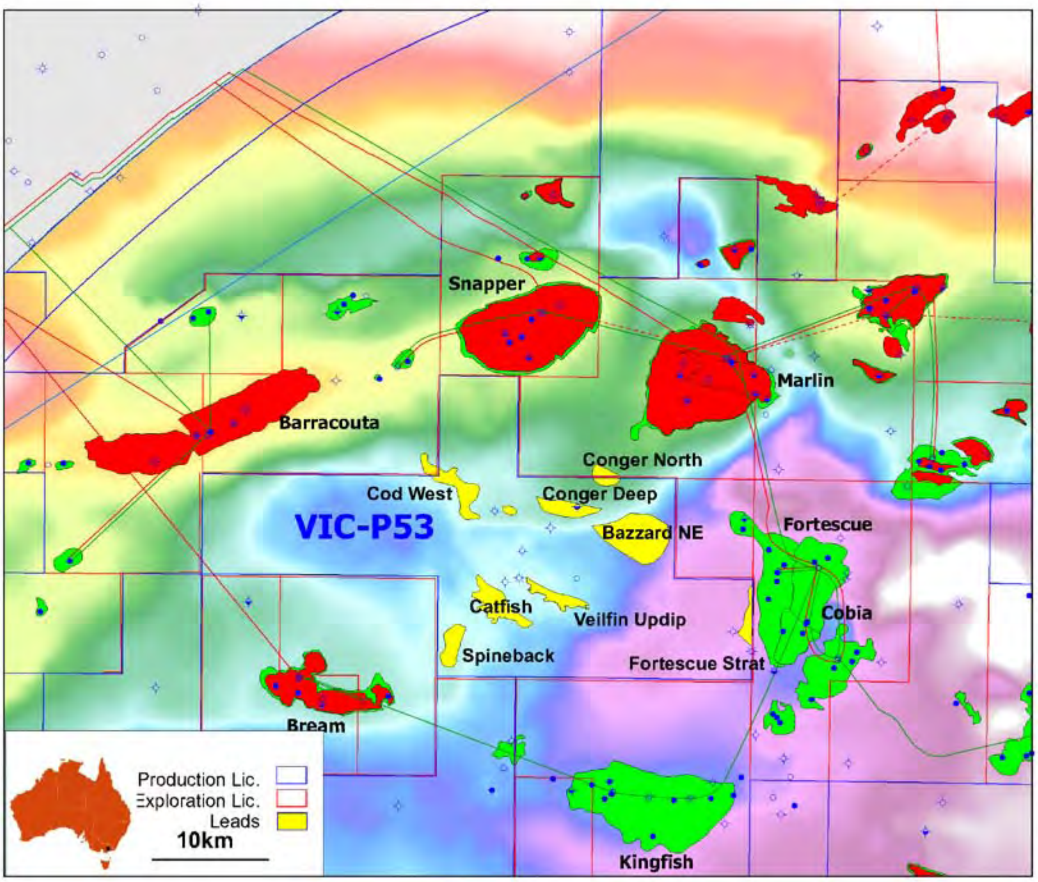

Figure 4. VIC/P53 Gippsland Basin, exploration leads and surrounding oil and gas fields.

PERMIT VIC/P53

Introduction

VIC/P53 covers an area of 740 square kilometres with water depths ranging from 40 to 75 metres (Figure 4).

Following a farmout of the permit to Stuart Petroleum Limited ("Stuart"), the VIC/P53 interest retained by Exoil is 16.6667%.

Stuart will meet 100% of the costs of two wells in the permit, subject to the right of Stuart to withdraw from the permit, at its election, after the conclusion of the first well, Bazzard 1, now completed. Stuart are yet to make such an election. If they do not elect to drill a second well, then their interest will be conveyed to Exoil and Moby. Stuart will assume its pro rata share of the overriding royalty (4%) obligations of Exoil and its joint venturers to Australian Crude Oil Company Inc. et al.

Exoil, as previous operator, acquired the 420 square kilometer Bazzard 3D seismic survey, and undertook new depth conversion seismic (PSDM) processing to refine the current prospects, including Catfish, West Cod and Updip Veilfin.

The permit is believed prospective for oil and gas at both the top Latrobe horizon and within the deeper intra-Latrobe sections. A number of prospective features at the intra-Latrobe have been identified on 3D seismic data which appear to be analogous to existing Gippsland Basin fields.

Previous Exploration

VIC/P53 is relatively sparsely explored, with only eight exploration wells drilled in the permit between 1965 and 1990, when, Sawbelly 1, was drilled. Bazzard 1 was drilled in September 2008. Before the acquisition of the Bazzard 3D seismic survey, seismic coverage was moderately extensive, but largely restricted to 2D surveys, vintages of which range from the 1960's to 1994. A closely spaced 2D seismic survey (the John Dory seismic survey), acquired by Esso/BHPP in 1988, was reprocessed to 3D equivalent data in 1994 by M.I.M. Petroleum Exploration Pty Ltd, but its quality is inferior to more modern 3D data.

Eight wells drilled in the permit to date targeted the top Latrobe Group plays. The first well, Cod-1 dates back to 1965 and was the third well drilled in the offshore Gippsland Basin. This was followed by Salmon-1 in 1969 and two more wells, Swordfish-1 and Rockling-1 in the 1970's. Veilfin-1, Drummer-1, Conger-1 and Sawbelly-1 were drilled in the 1980's. Bazzard 1 was an intra-Latrobe test.

Seismic interpretation suggests that most wells drilled two-way-time highs mapped at the top Latrobe level. However, because of velocity distortions, it is doubtful whether any tested valid depth closure at the top Latrobe horizon.

Rockling-1 and Drummer-1 were drilled to test structural-stratigraphic traps involving intra-Latrobe shoreface sandstones truncated by channels containing sealing claystones in the Cobia Subgroup and Lakes Entrance Formation.

Significantly, Veilfin-1 recorded noteworthy oil and gas shows. A production test in the intra-Latrobe (3,185 to 3,194 metres) flowed gas at 0.3 MMcfd and recovered a small amount of condensate. Wireline formation tests (RFT's) between 3,149 and 3,213 metres recovered minor gas with a scum of condensate. The hydrocarbons recovered at Veilfin-1 clearly establish the existence of a working petroleum system in the permit and the presence of effective intra-Latrobe seals.

Prospectivity

The prospectivity of VIC/P53 is considered to relate to four main play types:

1. Intra-Latrobe dip and fault controlled structural closures. This play comprises intra-Latrobe reservoirs, generally only locally sealed by intraformational claystones and mudstones. Veilfin-1 is a good example of a successful test of this play in VIC/P53. Many of the leads identified in the permit are coincident with those identified by previous operators including; Updip Veilfin, Catfish, Spineback (Figure 5b), and Hake all see (Figure 4).

2. Top Latrobe "Coarse Clastics" structural play. This play encompasses top Latrobe reservoirs sealed by Gurnard and Lakes Entrance formation claystones and marls. Structural traps comprise four-way-dip anticlinal "depth closures", which are either not evident or have been significantly displaced on two-way-time structure maps. The most prominent is the West Cod Prospect (Figure 5a).

3. Top Latrobe fault controlled structural closures. This play comprises top Latrobe reservoirs in fault traps sealed by Gurnard and Lakes Entrance formation claystones and marls. The main lead of this type identified in VIC/P53 is the Updip Veilfin Prospect.

4. Top Latrobe "Coarse Clastics" stratigraphic play. This top Latrobe play involves reservoirs sealed by Gurnard Formation and Lakes Entrance marls and claystones in stratigraphic traps. Stratigraphic closure is defined by composite erosional / depositional / dip-closed structures, comparable to the Fortescue, Halibut, Cobia and Mackerel oil fields in the production licences east of VIC/P53.

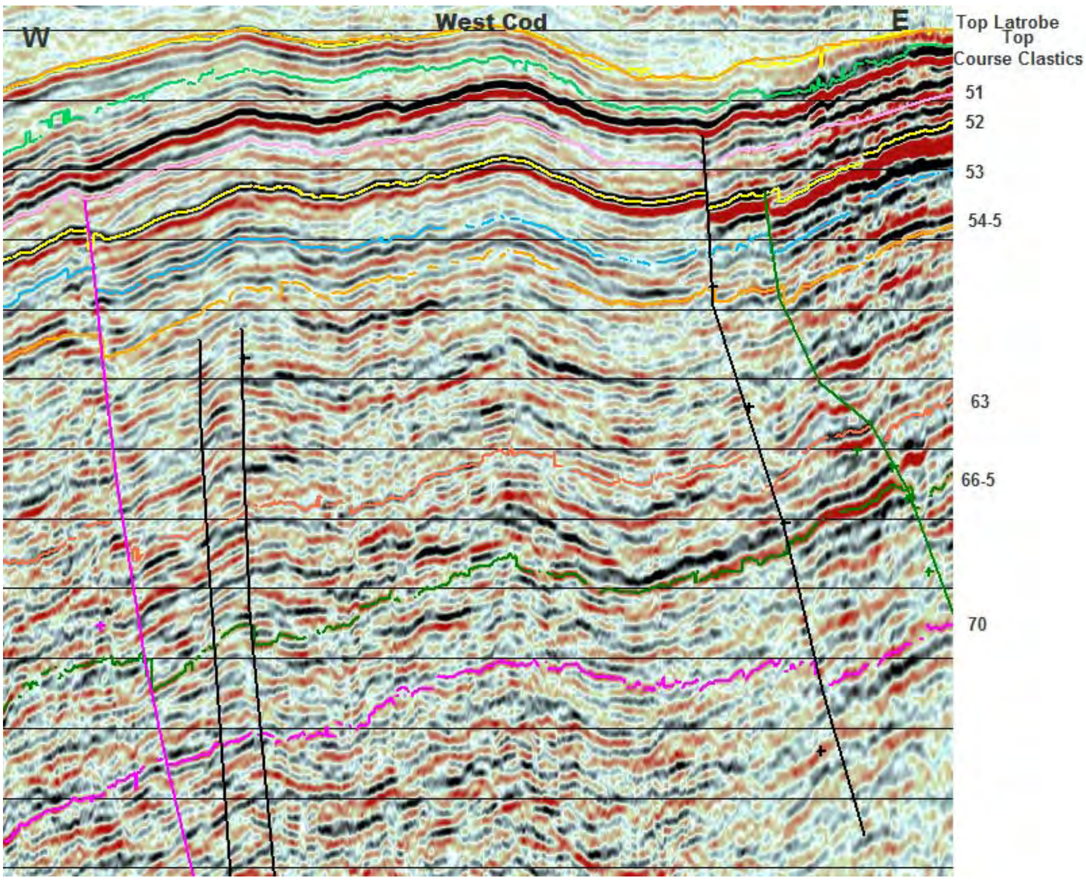

Figure 5a. VIC/P53 – West Cod Prospect

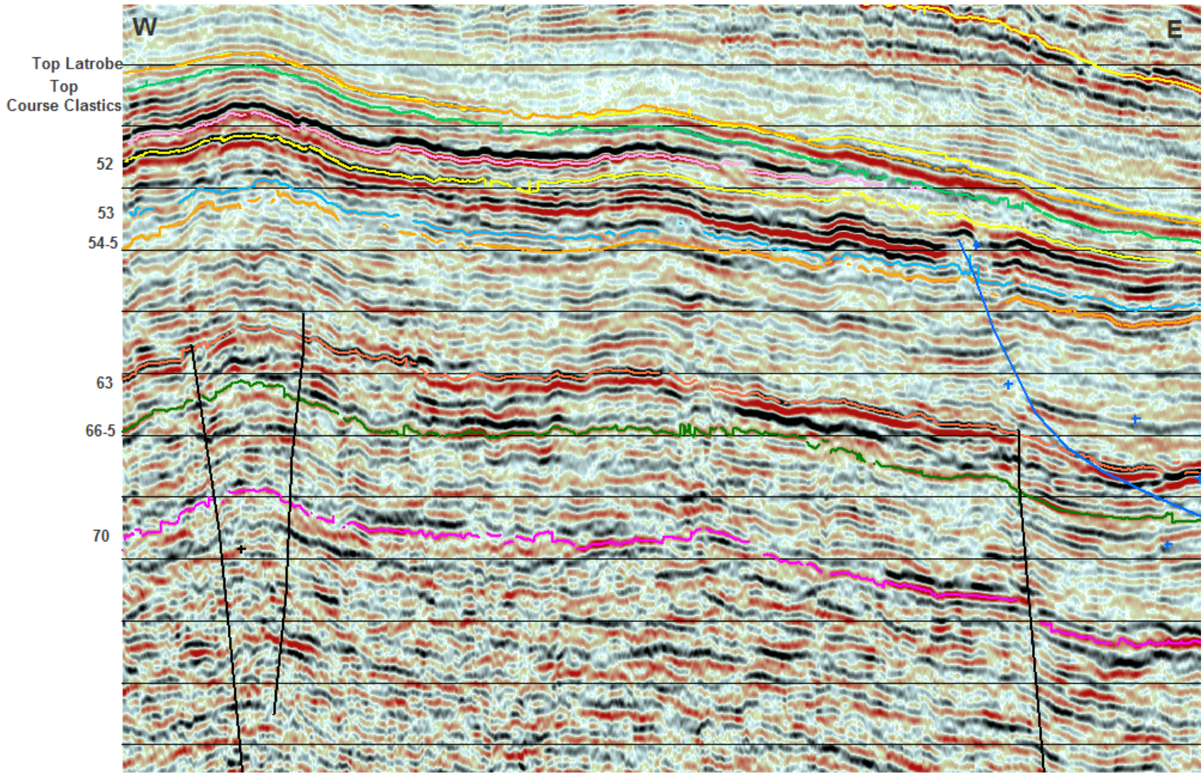

Figure 5b. VIC/P53 – Spineback Lead

Conclusion

VIC/P53 is centrally situated in one of the world's great hydrocarbon provinces and it is surrounded by oil and gas fields within the permit, a small non-commercial discovery has been made at the Veilfin-1 location within the intra-Latrobe sequence.

Interpretation of existing 2D seismic data in this region presents difficulties, which has historically prevented adequate definition of depth closure. Accurate depth conversion and enhanced seismic imaging in this area of the deep channeling Seaspray Group carbonates are critical factors for exploration success. The Bazzard 3D survey and associated studies were designed to address these issues.

In VIC/P-53 the company has negotiated a suspension of work programme conditions for the Year 3 of the Minimum Work Requirements in the permit. This suspension is for a period of 24 months, from 16th October 2006 to 15th October 2008. This suspension of 24 months allows for an extension of the term of the permit for a period of 24 months from 16th October 2009 to 15th October 2011. A further suspension of the permit for 12 months has been sought following the drilling of Bazzard 1.

The first year of the permit term contained a commitment to expedite G & G studies. The company committed to the acquisition of 200 square kilometres of 3-D seismic data. This commitment was met by the acquisition of the 420 square kilometre Bazzard 3-D Survey in 2005. The company committed to the drilling of two wells in the first permit term.

The first of these wells has been drilled by Stuart Petroleum (Offshore) Pty Ltd with, Bazzard 1, which was drilled in late September 2008. Should the company so decide it can elect to enter a second three year term in which it has indicated it will drill two wells and engage in further data evaluation.

In the opinion of the author, the company has developed and committed to a satisfactory and clearly defined work programme, which is reasonable having regard to the stated objectives of the company.

PERMIT VIC/P45

Introduction

VIC/P45 covers an area of some 900 square kilometres with water depths ranging from 80 metres in the north and west, to over 300 metres in the east (Figure 1).

Exoil holds a 50% interest in VIC/P45 and has become permit operator. Moby holds the other 50% interest.

Previously, Apache Energy Ltd (Apache) agreed a farm-in with the VIC/P-45 in which it would meet 100% of the costs of a first and second well to be drilled in VIC/P45, with the provision that Apache could withdraw from this commitment after drilling the first well, by reconveying the farmout interest (66.6668%) to Exoil and its partner.

The first well drilled under this agreement, the Coelacanth-1 well, reached a total depth of 3,074 metres, no material hydrocarbons were encountered. The results of this exploration well were announced along with the final abandonment preparations including wireline logging operations, on the 25th March 2008.

Shortly thereafter Apache withdrew from the Joint Venture under the terms described above, with the interest reverting to Exoil and its partner.

Previous Exploration

Nearly the entire permit is covered by a single, high quality 3D seismic survey acquired and processed in 2002/03. The eight wells drilled in VIC/P45 have tested prospects in all three of the main play groups (top Latrobe, intra-Latrobe and Golden Beach) with exploration success in the intra-Latrobe and Golden Beach plays. Three hydrocarbon discoveries, at Archer-1, Anemone-1A, and Hermes-1, clearly establish the presence of a working petroleum system in the permit (Figure 6). .

Archer-1 contains numerous pay zones of moveable oil encountered from 3,384 - 3,655 metres in an interval spanning the lower Latrobe Group and the upper part of the Golden Beach Subgroup. Zones of gas/condensate were intersected in sandstones directly below the oil zones and down to the well's total depth of 4,050 metres. Archer has been estimated to contain 7.6 MMbbl of oil-in-place (OIP), most of which is in the two uppermost reservoirs with net thicknesses of 20 and 21.8 metres. Gas-in-place (GIP) has been estimated at some 66.9 Bcf with most hosted in the two lowest reservoirs 5.9 and 9.2 metres thick.

Anemone-1A encountered two Golden Beach pay zones of 11 metres and 28 metres with average porosities of 14%. These zones have been estimated to contain a minimum proved and probable GIP of 11 Bcf with a maximum of 20 Bcf.

Evaluation work by the previous operator identified significant upside to the Archer and Anemone discoveries within the Archer Deep Prospect. This prospect has potential to contain almost 1 Tcf of recoverable gas with 100 MMbbl of condensate.

Hermes-1 discovered several gas/condensate zones in deep in blocky intra-Latrobe sandstones near total depth of 4,561 metres. Seismic interpretation and mapping showed the area of fault dependent structural closure to be small. This small volume together with poor reservoir quality has resulted in the identification of a sub-economic accumulation.

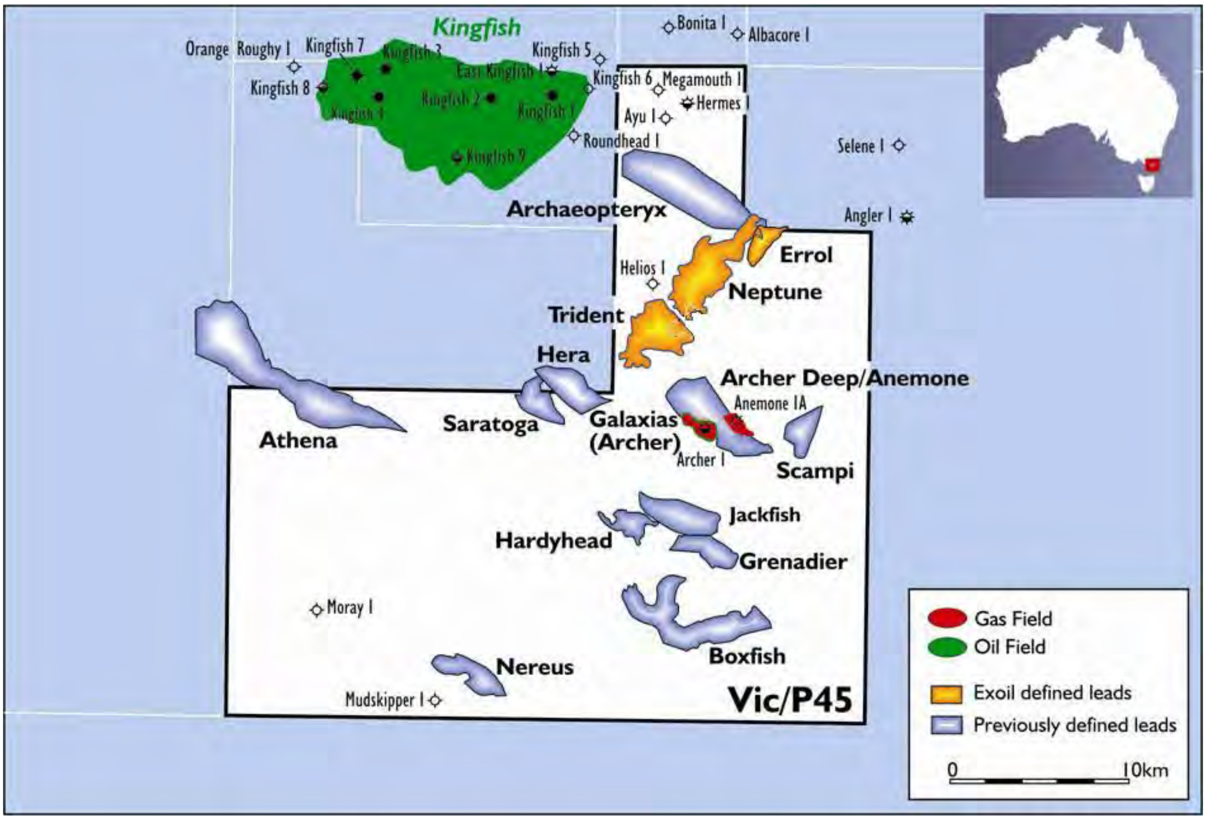

Figure 6. VIC/P45 Gippsland Basin, prospects and leads.

Prospectivity

Previously Defined Prospects and Leads

The major exploration potential identified through 3D seismic mapping of the area by a previous permit operator, relates to numerous structural and stratigraphic prospects and leads interpreted in Latrobe, Golden Beach and Emperor Subgroup sequences (Figure 6). The primary plays are top Latrobe siliciclastic sediments in 4-way or 3-way dip closures (for example the recently drilled Coelacanth-1 prospect); seismic amplitude driven low-side fault closures in the lower Latrobe and upper Golden Beach against the southern basin margin (Boxfish); and lowside 3-way or 4-way dip closures in the Golden Beach Subgroup (Archer Deep). Of the fifteen prospects and leads identified by the previous operator, four of them will be described here: Archer Deep, Scampi, Archaeopteryx and Saratoga.

The Archer Deep Prospect embraces the oil and gas discoveries made by Archer-1 and Anemone-1A. The new 3D seismic data suggests that Anemone-1A drilled across a fault into a deeper Golden Beach section on the Archer horst block not penetrated by Archer-1. Overpressure and poor quality reservoirs encountered in Anemone-1A were interpreted as resulting from drilling in the vicinity of the fault plane. Improvements in reservoir quality are anticipated up-dip, away from the fault. Ultimate recoverable reserves potential for gas and condensate in the lower Golden Beach reservoirs range from a low of 51 Bcf of gas and 3 MMbbl condensate, to a high of 923 Bcf of gas and 96 MMbbl condensate.

Scampi is an upthrown fault block lead involving stacked Cretaceous sands in a deep 4-way dip closure at the top Golden Beach horizon. The previous operator assessed reserves potential for the Cretaceous sands, in the primary target, at 34 MMbbl of recoverable oil. There is additional potential both above and below this primary target zone.

The Archaeopteryx Lead is a low relief 4-way dip closure generated at the palaeo-shelf break. The main risks with this lead relate to the accuracy of the seismic depth conversion. Recoverable reserve potential is estimated at 123 MMbbl.

The Saratoga Lead is a lowside fault-dependent closure at the Golden Beach level with estimated reserves potential of 34 MMbbl.

Exoil-developed Leads

Recent interpretation of 3D seismic data by Exoil has identified several promising intra-Latrobe plays involving structural-stratigraphic trapping mechanisms overlooked by previous operators (Figure 6). Further interpretation, mapping and reservoir characterization studies are required to fully assess the considerable potential of these leads.

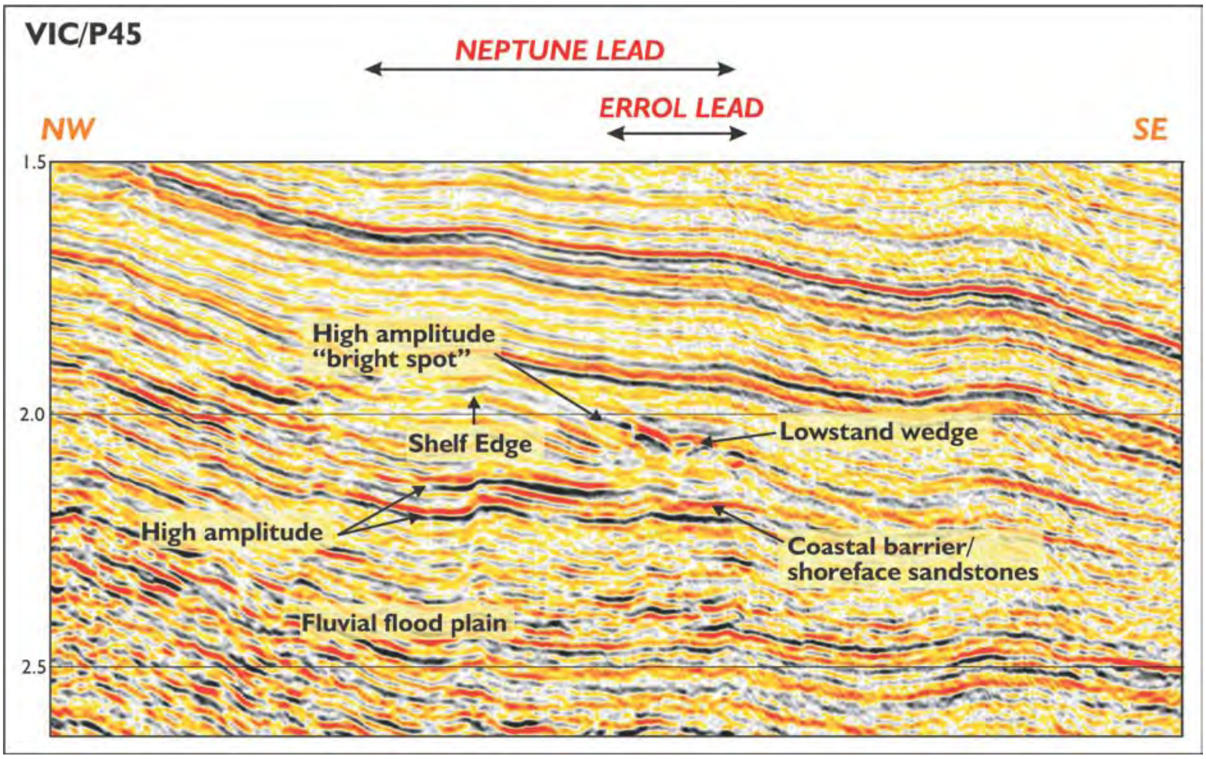

Figure 7. Seismic traverse across the Errol Lead showing the interpreted lowstand wedge, down-dip from a paleo-shelf edge, displaying bright seismic amplitudes. Underlying coastal barrier / shoreface sandstones also displaying high amplitudes, belonging to the underlying Neptune Lead, are also shown.

Errol Lead – a lowstand wedge. Interpretation of seismic facies and key surfaces in VIC/P45 reveals the presence of several prograding wedges in the upper Volador Formation (equivalent to the Roundhead Sandstone), deposited on the southeastern paleo-slope during periods of sea-level lowstand (Figures 7 and 8). The lowstand turbidite wedges thicken to the SE and form wedge-shaped depositional "thicks" that dip to the SE and strike NE-SW. These bodies provide reservoir plays for stratigraphically trapped hydrocarbon accumulations along the depositional trend of the paleo-shelf.

The Errol Lead is defined by a very strong, structurally concordant "bright spot" (Figures 7, 8 and 9). This can be interpreted as a possible DHI representing a gas accumulation. It implies the presence of an effective stratigraphic seal that provides an effective stratigraphic trapping mechanism.

Errol is located in a particularly "oily" part of the Gippsland Basin with significant potential for the presence of a substantial oil leg, down-dip of the interpreted gas. The lead as presently defined, encompasses 2.7 square kilometres, but its size could be substantially greater if the oil leg extends further down-dip. Additional work is necessary to more fully evaluate the potential of this lead.

Neptune and Trident leads – coastal barrier/shoreface sandstones. In the central part of VIC/P45, seismic sections and mapping calibrated by well ties, reveal sediment thicknesses associated with several, aerially extensive, NE-SW trending, coarsening-upwards sandstone bodies (Figures 7, 10 and 11). . Based on the mapped extent of the upper sandstone, the Neptune Lead encompasses an area of 12.8 square kilometres and Triton some 9.6 square kilometres.

Several sandstones are present forming stacked sequences within the upper part of the Volador Formation as shown by the seismic line in Figures 10 and 11. The equivalent sandstones intersected by Helios-1 (20 – 80 metres thick), although water wet in this down-dip well location, exhibit excellent reservoir properties.

Exoil has interpreted the sandstone bodies as representing laterally restricted, transgressive coastal barrier to shoreface sandstones that display a SE transition into offshore sealing marine claystones. Vertical seal is considered to have been provided by intraformational, transgressive marine claystones that extend from the SE to the NW. At Helios-1, the marine claystones merge with lagoonal and lower coastal plain sediments in a landward position behind the barrier.

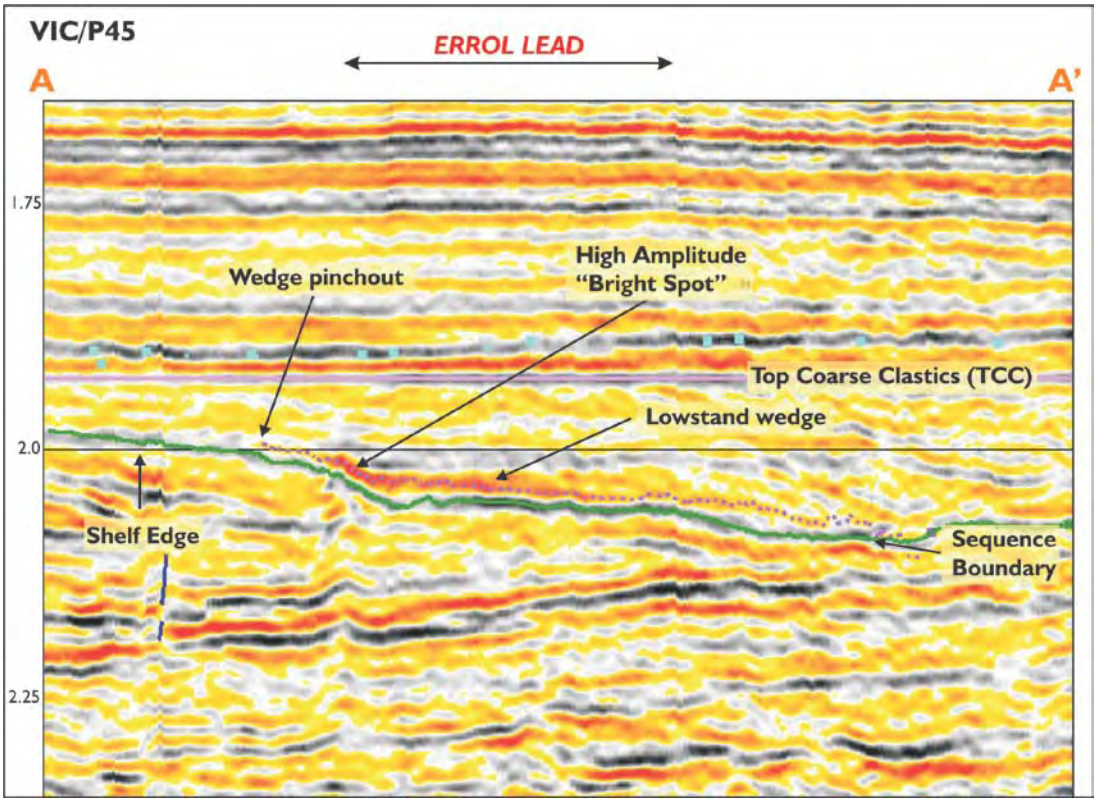

Figure 8. Detail of seismic traverse across the Errol Lead lowstand wedge flattened on the 'Top Coarse Clastics' (TCC).

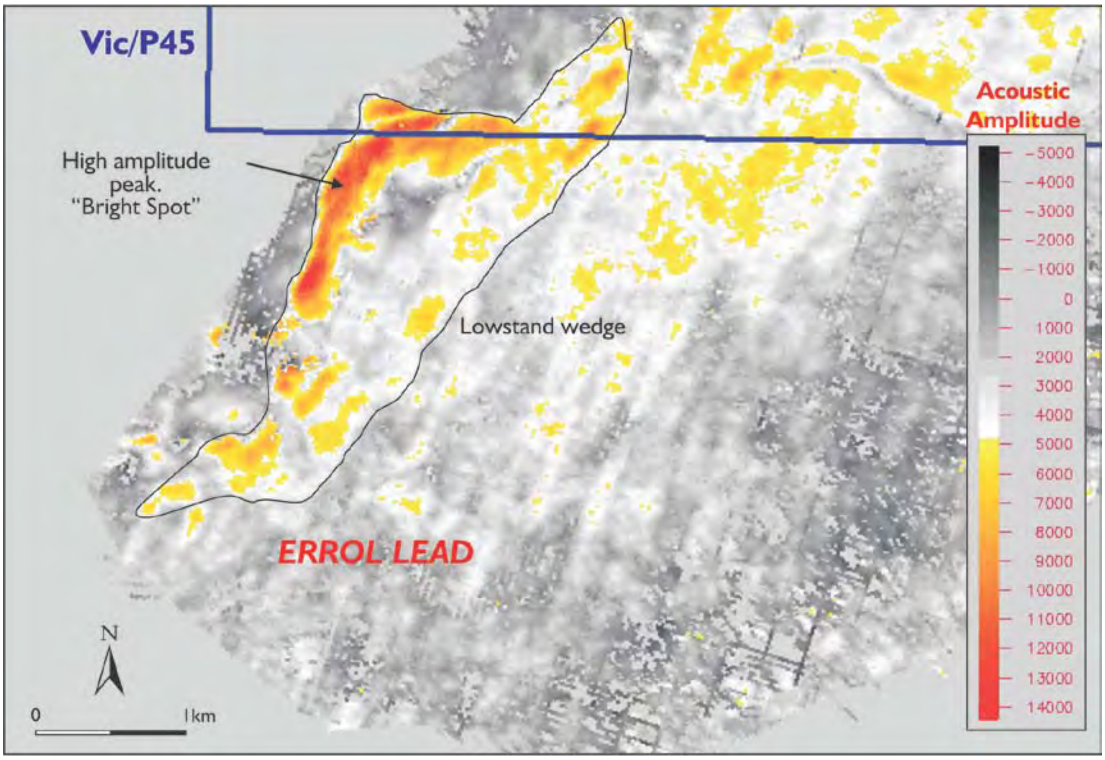

Figure 9. Horizon slice showing peak amplitude of the Roundhead Member lowstand wedge over the Errol Lead.

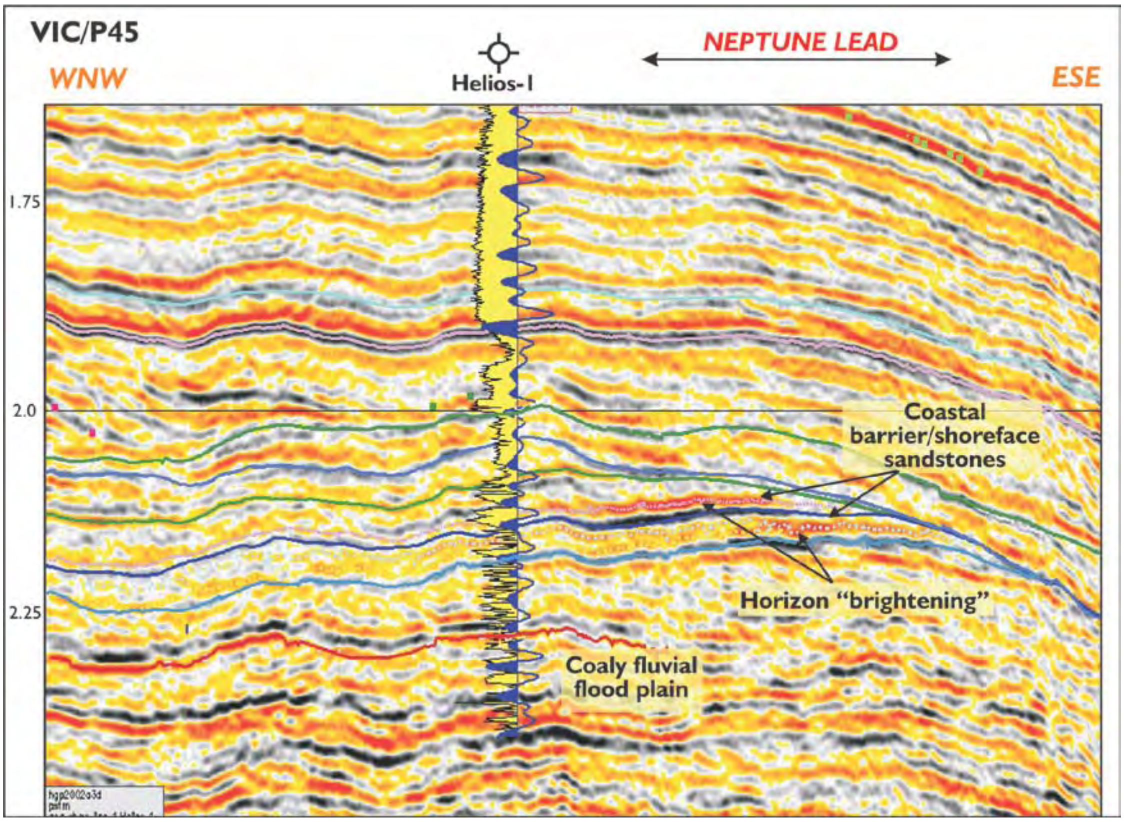

Figure 10. Seismic traverse across the Neptune Lead, up-dip from Helios-1, showing stacked barrier / shoreface sandstones in the Volador Formation – see Fig.3, displaying bright seismic amplitudes.

Changes in seismic amplitude of a reflector within or bounding a reservoir interval can be due to changes in lithology, porosity, seismic tuning effects and fluid content. In some cases, high amplitude (or a "bright spot") can be indicative of a gas charged sand and therefore represent a direct hydrocarbon indicator (DHI).

The high amplitudes that characterise the interpreted barrier sandstone system of the Neptune and Trident leads are intriguing and could imply the presence of hydrocarbons. The seismic requires additional processing and analytical techniques, for example, amplitude variation with offset (AVO), to determine more precisely the variable contributions of porosity, lithology (reservoir/seal) and fluids (oil, gas or formation water).

Conclusion

Exploration in VIC/P45 for large hydrocarbon accumulations relies on the identification and definition of intra-Latrobe combination structural-stratigraphic traps, together with a better understanding of the cause of high amplitude reflections associated with potential sandstone reservoirs.

VIC/P45 contains a number of prospects and leads yet to be drilled, some associated with possible direct hydrocarbon indicators. Although higher risk targets than conventional four-way-dip closures, the combination structural-stratigraphic traps may be prospective for hydrocarbons given the extensive coverage of high-quality 3D seismic and the presence of adjacent producing fields.

In VIC/P-45 Exoil committed to geological and geophysical studies and the drilling of a second well in the minimum work requirement period of the first three years. This second well, Coelecanth 1, has been drilled. Should the company so decide it can elect to enter a second three year term which presently has an indicated program of two wells and the possible reopening of two existing wells. The Company plans to enter the second three year period.In the opinion of the author, the company has developed and committed to a satisfactory and clearly defined work programme, which is reasonable having regard to the stated objectives of the company.

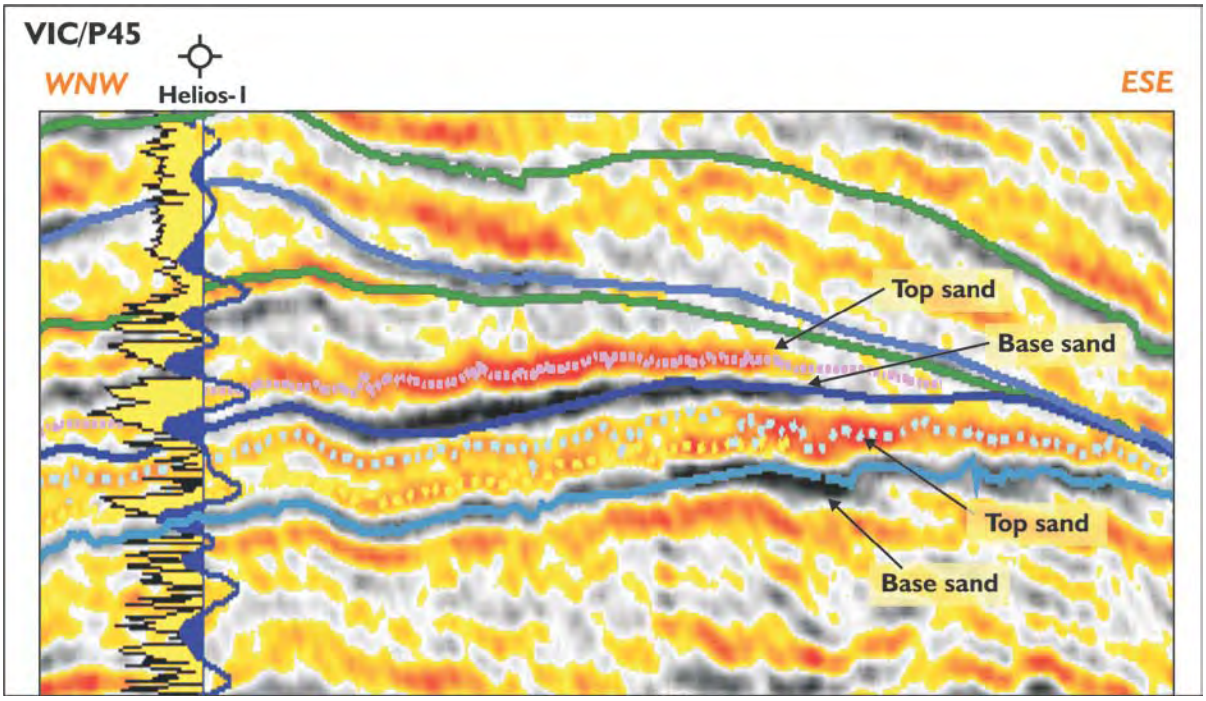

Figure 11. Enlargement of seismic traverse across the Neptune Lead showing detail of bright seismic amplitudes.

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SECTION 2

THE BASS BASIN TENEMENTS – T/37P & T/37P

Exoil Limited holds 35% interests in two adjacent offshore petroleum exploration permits, T/37P and T/38P, with the exception of part of T38P (see Beach – Spikey prospect following). Both are located in Bass Strait, north of Tasmania and east of King Island. Each permit comprises 40 graticular blocks, covering areas of 2,670 square kilometres (T/37P), and 2,655 square kilometres (T/38P). Water depths across both are less than 75 metres. The permits are adjacent to the Yolla gas/condensate (BassGas) production development and the White Iris 1 and Trefoil-1 gas/condensate discoveries in exploration permit T/18P, both operated by Origin Energy Resources Limited. (Figure 12).

Recently, Exoil has reached an agreement with Beach Petroleum Ltd ("Beach") to farm out an 80% interest in a part of the permit T/38P. Beach will earn an 80% interest in a defined portion of the T38P permit by paying for the drilling of the Spikey-1 exploration well. It will be operated by Beach and is expected to be drilled in the second half of 2008. Exoil Ltd will retain 35% in each of the remainder of T/37P and T/38P licences.

History of Exploration in the Bass Basin

The Bass Basin is moderately explored with 35 wells drilled since 1965, a drilling density of just one well per 1,320 square kilometres. Drilling results indicate that 20 of the 35 wells had significant hydrocarbon shows. Further analysis suggests that almost one third of the wells were invalid tests, either drilled off-structure or failures due to misinterpreted seismic. Several wells were dry because volcanic rocks were misidentified as direct hydrocarbon indicators (DHI's) or carbonate reefs.

Exploration in the basin commenced in the early 1960's with the award of petroleum exploration permits to an Esso-led joint venture comprising Esso Exploration and Production Australia Ltd (Esso) and Hematite Petroleum Pty Ltd (BHP Petroleum - BHPP). Bass-1 was the first well in the basin; it was drilled in 1965 by the Esso/Hematite joint venture. The subsequent drilling program involved 15 wells over the ensuing nine year period. This early exploration phase resulted in gas/condensate discoveries at Pelican-1 and Pelican-2, with significant oil and gas shows at Bass-3, Cormorant-1, Pelican-3, Poonboon-1, Toolka-1 and Aroo-1.

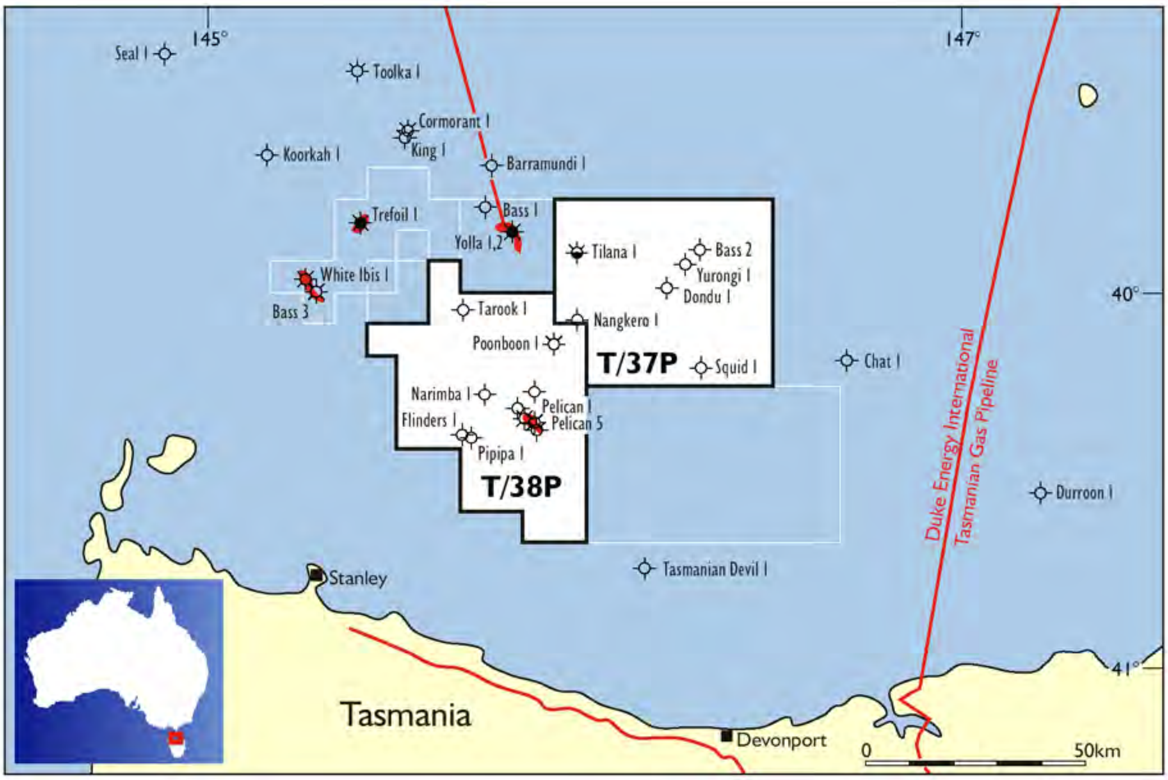

Figure 12. T/37P and T/38P Bass Basin, showing exploration wells, gas fields and pipelines.

The Yolla gas/condensate field, reservoired in the Eastern View Group, is the Bass Basin's most significant discovery. It was recently successfully appraised by the Yolla-3 and -4 development wells. The field is reported to contain a resource of 450 to 600 Bcf of liquids-rich gas containing an in-place volume of 70 million barrels of condensate and oil. Development of the field was completed in mid-2005 with production facilities at the offshore platform connected to the new BassGas pipeline that delivers gas northwards to Victoria.

The Pelican gas/condensate accumulation which is located in the Company's permit T/38P, has been appraised by five wells, most recently Pelican-5 which was drilled in 1985/86. Multiple hydrocarbon-bearing sandstones of Palaeocene to Early Eocene age were penetrated in a large faulted anticlinal closure. Wireline formation tests (FIT's and RFT's) suggest that many of the sandstones have low permeability, but a drill-stem-test (DST) in Pelican-5 provided some encouragement. The test of a Lower Eocene gas-bearing sandstone interval in the "Middle Eastern View Coal Measures" flowed gas at a maximum rate of 5.5 MMcfd accompanied by 400 barrels of condensate per day. Further studies are required to examine the commerciality of this resource (e.g. using horizontal drilling and production methods) and its potential for linkage to the BassGas pipeline.

White Ibis-1 (1989), located in exploration permit T/18P to the northwest of T/38P, was a crestal test over a large basement high up-dip of a previous exploration well, Bass-3. Formation pressure data suggest the presence of a thin oil rim and an overlying gas accumulation with an estimated in-place resource of 85 Bcf.

Trefoil-1 (2004), also located in exploration permit T/18P, northwest of T/38P, was a new gas field discovery with multiple reservoirs within the Eastern View Coal Measures. Several of the gas-bearing sandstones exhibit evidence of direct hydrocarbon indicators (DHI's) on seismic sections, this evidence includes strong AVO anomalies and frequency attenuation anomalies. The demonstrated presence of DHI's can be used to guide exploration elsewhere in the basin.

DST No. 1 over the perforated interval 3,141 - 3,150 metres flowed gas at a final rate of 16.3 MMcfd at a tubing pressure of 1,329 psi through a 48/64 inch choke. This gas flow was accompanied by 145 barrels of condensate per day. DST No. 2 from 3,040.5 - 3,046.5 metres flowed gas at a final rate of 9.9 MMcfd at a flowing wellhead pressure of 645 psi through a 56/64 inch choke, accompanied by 253 barrels of condensate per day.

Trefoil-1 reportedly intersected some 50 metres of net gas pay over eight zones in good quality sandstone reservoirs in the Eastern View Coal Measures, the same formation currently producing at the nearby Yolla gas/condensate field. Significantly, live oil indications were also reported in the well. An "in-place" resource for the field of 100 to 300 billion cubic feet of gas with associated liquids is indicated. The gas is said to be of a high quality (~3% CO_2) with liquids content ranging from 10 - 25 barrels per million cubic feet of gas. The discovery has potential for commercial development through linkage with the Yolla and BassGas Pipeline.

Regional Geology

The Bass Basin is a NW-trending, intracratonic rift basin that underlies the Bass Strait region between northern Tasmania and southern Victoria (Figure 13). The basin is separated from the Otway and Sorell basins to the WNW by King Island, and from the Gippsland Basin to the NE by Flinders Island and the Bassian Rise (Figure 14).

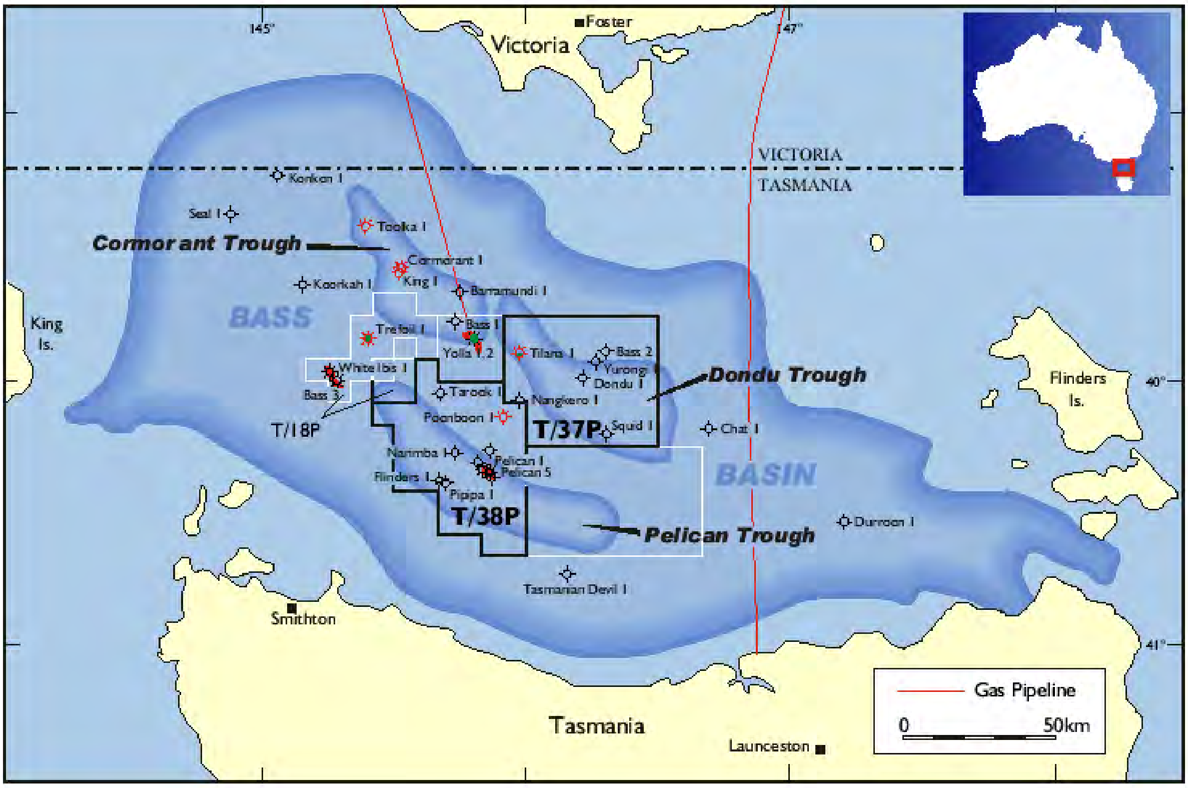

Figure 13. Location map of the Bass Basin and adjacent region, southeastern Australia showing the basin outline, permits, well and field locations.

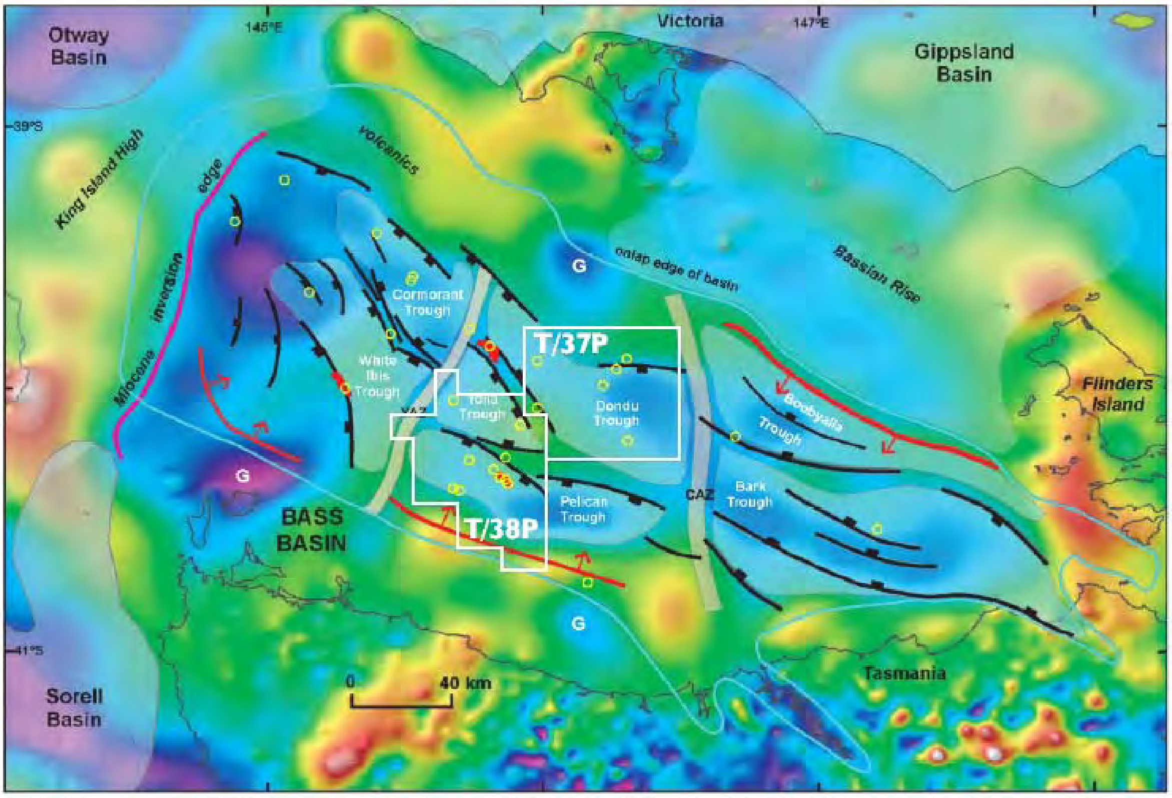

Figure 14. Bouguer gravity anomaly map of the Bass Strait region showing wells, tectonic setting and structural elements of the Bass Basin.

Tectonic Development

Along with the adjacent Otway, Gippsland and Sorell basins, the Bass Basin was initiated in the Late Jurassic to Early Cretaceous (Tithonian-Barremian) as part of the Southern Rift System. This major rift system extended from Broken Ridge in the west to the South Tasman Rise in the east. Extension during the Jurassic and Early Cretaceous resulted in the formation of a series of WNW-trending continental rift basins along the southern margin of Australia together with a series of NNW-trending transtensional basins along the western margin of Tasmania.

The Bass Basin is characterised by a half-graben structural style, with Palaeozoic and Proterozoic basement fault blocks bounded by large displacement normal faults (Figure 14). Vertical displacements on the normal faults are of the order of 3 to 5 kilometres. The total sedimentary succession (syn-rift and post-rift sections) reach a thickness of 8 to 10 kilometres in the main depocentres. The half-graben compartments in the central and western Bass Basin have been informally named the Cormorant, Yolla, and Pelican troughs.

The Bass Basin was affected by multiple periods of deformation. At least three phases of upper crustal extension occurred from the Early Cretaceous to Early Eocene times.

The syn-tectonic Otway/Eumeralla successions deposited during the Early Cretaceous rift phases (Otway/Eumeralla and Durroon sequences) are well imaged on seismic within the deeper half-grabens, but have rarely been penetrated by drilling due to the depth of their burial. In the central and western Bass Basin, the oldest sediments penetrated by drilling are Late Cretaceous in age.

Until the Late Eocene, deposition of non-marine sediments in the Bass Basin was controlled by internal drainage systems that migrated from the uplifted flanks of the basin into the developing half-graben basins. Following the cessation of rift-related activity late in the Early Eocene, accommodation was controlled by normal post-rift subsidence and sea level fluctuations. Widespread marine flooding of the basin occurred from west to east following the initial emplacement of seafloor crust in the flanking Otway Basin during the Middle Eocene, although indications of periodic earlier marine incursions are recorded locally.

Multiple periods of post-rift tectonic reactivation, including several episodes of Tertiary inversion, are recognised in the Bass Basin. These compressional events formed large scale anticlines within the syn- and post-rift successions. Several of these structures have been targeted by exploration drilling.

The Bass Basin and adjacent areas on mainland Tasmania and Victoria have been affected by multiple periods of volcanic activity during both syn-rift and post-rift phases of basin development. Offshore, these events are marked by the widespread emplacement of intrusive and extrusive rocks, particularly in the southern and western parts of the Bass Basin where they are associated with large-scale faults and structural accommodation zones (Figure 14).

Stratigraphy

Recent technical work integrating the biostratigraphy, with sequence and seismic stratigraphy, has resulted in a new sub-division of the Bass Basin stratigraphic succession by Blevin (2003). This work has been reviewed in the offshore area release document prepared by the Australian Government (2004). In addition a regional potential field interpretation report has been authored by Teasdale et al. (2003) and an audit of exploration wells in the Bass Basin is to be found in Trigg et al. (2003). These studies have provided valuable new insights into the petroleum potential of the Bass Basin.

The reappraisal of the stratigraphy has revealed the presence of six sequences – megasequences and supersequences – (Figure 15), they are related to distinct phases of tectonic activity and eustatic fluctuations. Sequences of economic interest in the Bass Basin include the Bass (Furneaux and Narimba), Eastern View, and Demons Bluff sequences. The Durroon and Otway sequences lie in the deepest parts of the half-graben troughs and do not as yet present viable drilling targets in the two Exoil permits.

The Bass Megasequence (equivalent to the "Middle Eastern View Coal Measures") comprises the mid-Campanian to Maastrichtian Furneaux Sequence and the overlying Maastrichtian to Lower Eocene Narimba Sequence. Each sequence corresponds to an episode of rift activity, which was focused in the Pelican, Cormorant and Yolla troughs in the western Bass Basin. These sequences are largely terrestrial, with intermittent brackish/marine influences, which are evident within the Early Paleocene and Early Eocene sedimentary section.

Sedimentation occurred within an internal drainage basin setting, with fluvial systems feeding into the slowly subsiding troughs from the uplifted basin flanks. Expanded sections of aggradational, fluvio-deltaic sandstones/siltstones and finer-grained lacustrine sediments accumulated in the rapidly subsiding troughs. On the rift flanks, sediments form thinner, stacked successions of fluvial-deltaic sandstones and interbedded over - bank claystones, mudstones and thin coal beds.

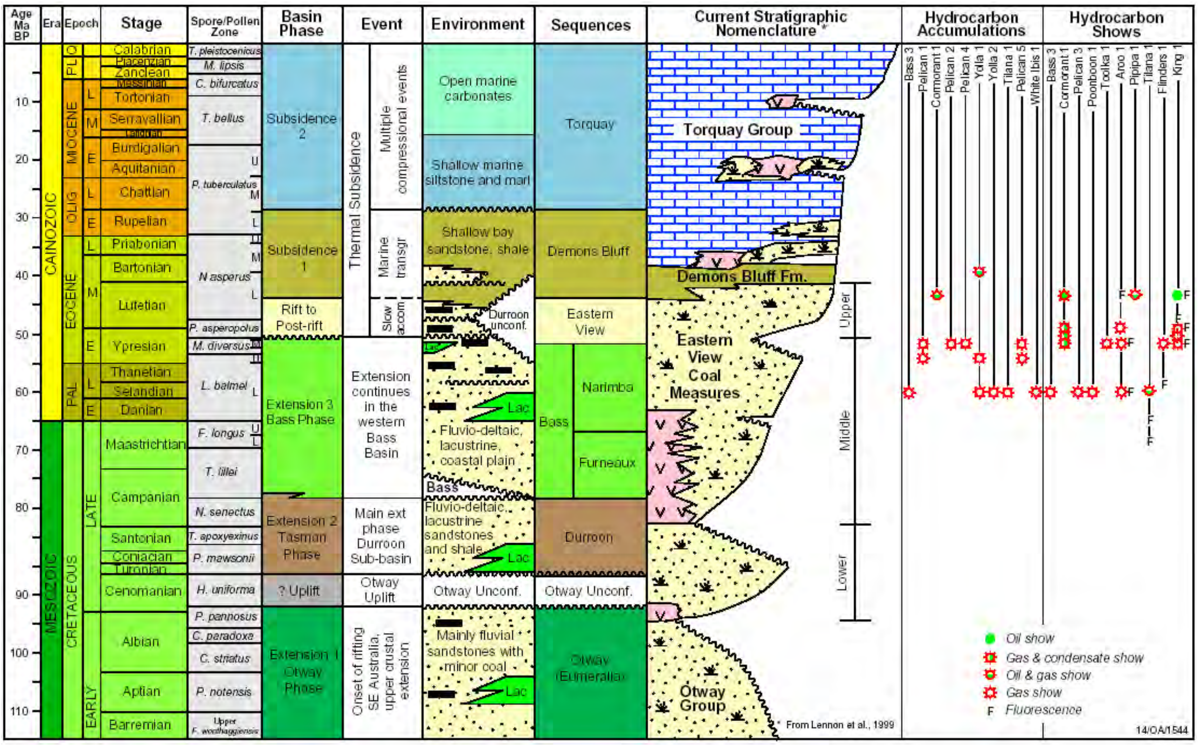

Figure 15. Stratigraphic correlation chart for the eastern Bass Basin showing the stratigraphic position of hydrocarbon shows and accumulations.

The coal-rich Eastern View Sequence (the "Upper Eastern View Coal Measures") formed in the latest Early Eocene to Middle Eocene, when rift-related tectonic activity in the Bass Basin began to wane. This transitional period represents the crustal evolution of rift to post-rift subsidence, a process which resulted in a rapid decrease in the rate of accommodation and a distinct change in depositional style. At this time, the basin had relatively low relief and sediments were deposited in low-energy, meandering fluvial environments flanked by flood plains and ephemeral lakes. From the latest Early Eocene until the early Middle Eocene (Upper *M.diversus* and *P.asperopolus* spore/pollen zones), coal beds up to 25 metres thick accumulated in peat mires that fringed the margins of the former rift depocentres. Lakes were preferentially formed in areas of maximum subsidence overlying half-grabens, these can be found particularly in the northern and western parts of the basin.

The Middle to Upper Eocene Demons Bluff Sequence represents the early period of post-rift subsidence. Fluvial environments continued to dominate in the eastern part of the Bass Basin, while thin coals and fine-grained sediments accumulated in lower delta plain and paralic environments farther west. Lakes and restricted marine lagoons filled the central and western parts of the basin, as marine water encroached from the west. Fluctuations in sea level resulted in rapid shifts of facies along the basin margins, although sedimentation within the deeper parts of the basin was probably continuous.

In the late Middle Eocene (Middle *N.asperus* spore/pollen zone), a short regression led to incision across much of the basin and the deposition of a widespread sand facies. Locally, this regressive sandy facies is known as the “Boonah Formation” and represents the “top reservoir” horizon across most of the basin.

A rapid flooding of the basin occurred in the Late Eocene resulting in the deposition of a thick, potentially regional sealing “Demons Bluff Formation” which is comprised of shallow bay siltstones and shales. The predominantly terrestrial nature of sedimentation in the Bass Basin until the Late Eocene ensures that the reservoir and seal facies occur as interfingering and interbedded units that do not form regionally extensive seals.

The Late Oligocene to Recent - Torquay Sequence consists of a lower argillaceous (mud and marl) succession up to 650 metres thick, overlain by a calcarenite-dominated succession up to 860 metres thick, which ranges in age from Late Miocene to Recent. There is evidence of extensive volcanic activity in the Bass Basin at this time, particularly in the southeast and western regions of the basin.

Petroleum Systems in the Bass Basin

The hydrocarbons discovered on the southern margin of Australia are assigned to the Austral Petroleum Supersystem based on the age of their source rocks and common tectonic history. In the Bass Basin, exploration drilling has confirmed gas, condensate and oil accumulations at Yolla, Pelican, White Ibis, Cormorant, and Trefoil, which have been reservoired in sands of Palaeocene to Eocene age (Figures 15). At present, only the accumulation at Yolla has been developed by the $450M BassGas Project operated by Origin Energy.

The oils have a terrestrial source affinity and are geochemically similar to Gippsland Basin crude oils. Geochemical analyses of the hydrocarbons indicate that the source rock kerogens consist predominantly of land-plant material with no evidence of marine organic matter input. The Yolla-1 oil is a medium-gravity (46^{o} API) crude with a high wax content. The Cormorant-1 oil has a similar origin but is a heavy crude (21^{o} API), which is considered to be due to the effects of biodegradation.

Oil-to-source correlations undertaken by Geoscience Australia have shown that the oils were sourced by Tertiary coals, particularly those concentrated within the Middle to Lower Eocene succession. Oils in the basin belong to a single oil population (Yolla and Pelican accumulations) although in-reservoir biodegradation of the Cormorant oil has resulted in its statistical classification as a separate oil family.

Recent fluid inclusions studies have identified palaeo-oil zones at Yolla-1 and Cormorant-1, along with suspected zones at King-1 and Pelican-5. In addition, several potential palaeo-hydrocarbon zones were identified at Yurongi-1, Chat-1, Seal-1, Tilana-1 and Squid-1. These zones are characterised by aqueous inclusions containing small amounts of oil. Overall, the pattern of hydrocarbon distribution in the basin shows that hydrocarbon generation has occurred in the Cormorant, Yolla and Pelican troughs, with migration into structures within the depocentres and across the adjacent flanks.

Petroleum Potential related to T/37P and T/38P

The usual exploration risks apply in the Bass Basin and to the Company’s two tenements, namely the requirement for:

(i) mature source rock,

(ii) reservoir,

(iii) seal and

(iv) trap.

Each one of these risk elements is examined below:

(i) Source Rocks and Maturation

Source rocks in the Bass Basin are non-marine and include Late Cretaceous to Middle Eocene coals and carbonaceous claystones (Figure 15) deposited in low-energy fluvial, deltaic and lacustrine environments. The coals form seams between 5 metres and 25 metres thick. They are rich in extractable organic matter with significant petroleum generation potential. Coals within the upper Bass and Eastern View sequences generally have high hydrocarbon indices and contain abundant exinite and vitrinite.

Differences in the organic character and relative abundance of coals have been recognised and are attributed to fluctuations in regional water tables and sea level during deposition.

Coals are generally thicker and occur more frequently within the younger Eastern View Sequence. These younger coals are richer in exinite and poorer in inertinite than the older coals within the underlying stratigraphic succession. Source rocks are primarily of Type II and Type III and, although predominantly gas prone, they also have potential for significant hydrocarbon liquids generation.

The basin-wide onset of oil generation determined by vitrinite reflectance occurs at a depth of around 2,700 metres. Subsidence and maturation modelling indicates that potential source rocks in the Upper Cretaceous succession have been mature since late Middle Eocene times. Importantly, this post-dates the end of rift formation and trap development in the Pelican Trough. Migration from mature source rocks into available traps may have occurred via local fault-related conduits and intra-stratal fairways. The overlying Upper Eocene and younger marine succession (Demons Bluff and Torquay sequences) are immature for hydrocarbon generation across the basin.

Significant thicknesses of mature source rocks in the Bass and Eastern View graben sequences are present in both T/37P and T/38P. Deeper, undrilled source rocks may also be present in the underlying Durroon and Otway sequences.

(ii) Reservoir Rocks

Proven petroleum-bearing reservoirs in the Bass Basin occur within the Palaeocene and Lower Eocene succession

(Bass and Eastern View sequences). These reservoirs are predominantly fluvio-deltaic sandstones 20 to 50 metres thick. Facies analysis and correlation of cores with wireline logs suggests that reservoir sandstones were deposited in a range of terrestrial, paralic and shallow marine environments. The lateral continuity of these facies varies widely. Porosity analyses on cores and sidewall cores at Cormorant-1 and Yolla-1 recorded average values of 15 to 25% while permeabilities range from 16 to 308 millidarcies. In general, porosity declines moderately with increasing depth (approximately 5.7% per 1,000 metres). A study of the nature and distribution of porosity suggests that present-day reservoir quality is best developed above 2,700 metres.

(iii) Seals

Hydrocarbon accumulations such as the Yolla and Pelican gas fields (the latter located in T/38P) are reservoired in anticlinal structures within the Bass and Eastern View sequences. These stacked reservoir sequences are sealed by intraformational shales deposited in lacustrine and interdistributary bay to floodplain environments.

The Upper Eocene Demons Bluff Sequence contains a marginal marine to shallow marine shale that blankets much of the Bass Basin, but is thin or absent in the southeastern Durroon Sub-basin where it has been eroded due to uplift. Where present, the Demons Bluff sequence forms a thick regional seal over the underlying terrestrial reservoir successions. Seal analyses of recent wells such as Barramundi-1, have highlighted the negative effects of late stage reactivation events on trap integrity. Late stage reactivation has often resulted in localised fracturing and faulting of the Demons Bluff regional seal.

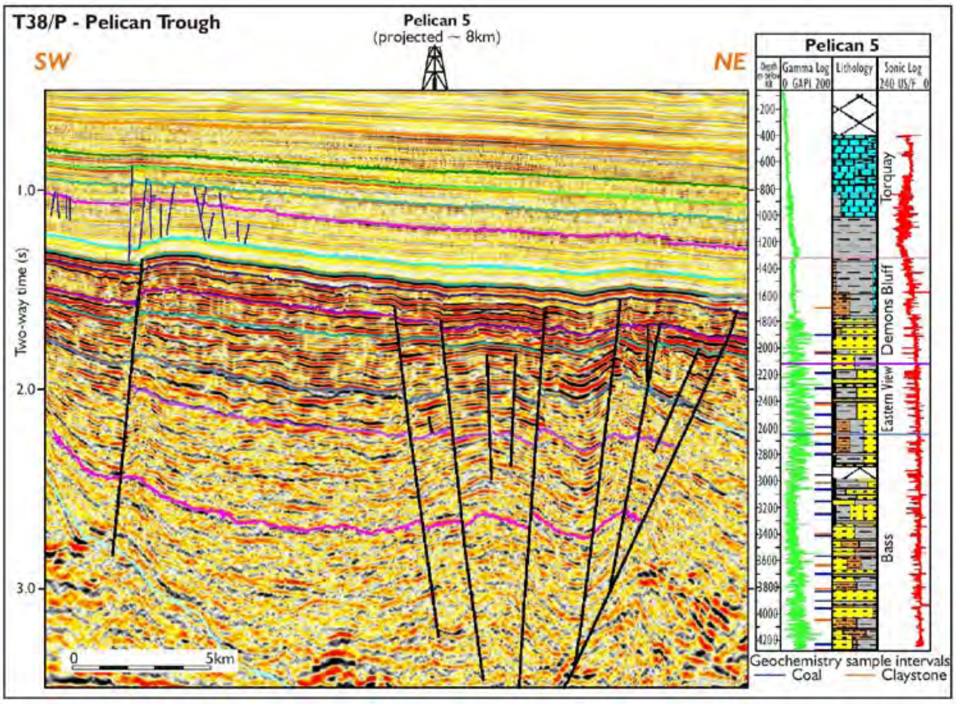

Figure 16. Seismic cross-section across the Pelican Trough in T/38P close to the Pelican gas field.

(iv) Play Types and Petroleum Traps

The Company's tenements are located in the central part of the Bass Basin. Permit T/38P contains the Pelican gas field discovered by Esso in 1970 and last appraised in 1985 (Figure 16). A number of exploration wells, either discoveries or with strong hydrocarbon shows have been drilled in the surrounding region (Figure 12) including the Yolla field located to the west of the tenements.

Play types include rotated fault blocks with drape closure and anticlinal structures that have formed in shallower strata during Tertiary compression (Figure 17). A large number of stratigraphic plays are also indicated in the data, but these require additional and higher quality seismic to define them.

Prospectivity

T/37P

There are presently three recognized leads in the T/37P permit, they are:

NW Nangkero - which is shared between T/37 and T/38P.

The Leonang lead.

The Squid West Fairway area.

NW Nangkero is located immediately SSE of the Yolla Field to the west of T/37P, it is defined by a limited volume of seismic data. NW Nangkero is an anticlinal fault bound Early Miocene to Late Oligocene structure, with faulting on the northern and eastern flank and dip closure to the south west. The lead is considered likely to be gas charged, correlation with adjacent wells is indicative of potential for good quality multilevel reservoirs. The lead demonstrates a well developed structural expression at the top of the Eastern View Coal Measures seismic horizon. The lead straddles the boundary of permits T/37 and 38P.

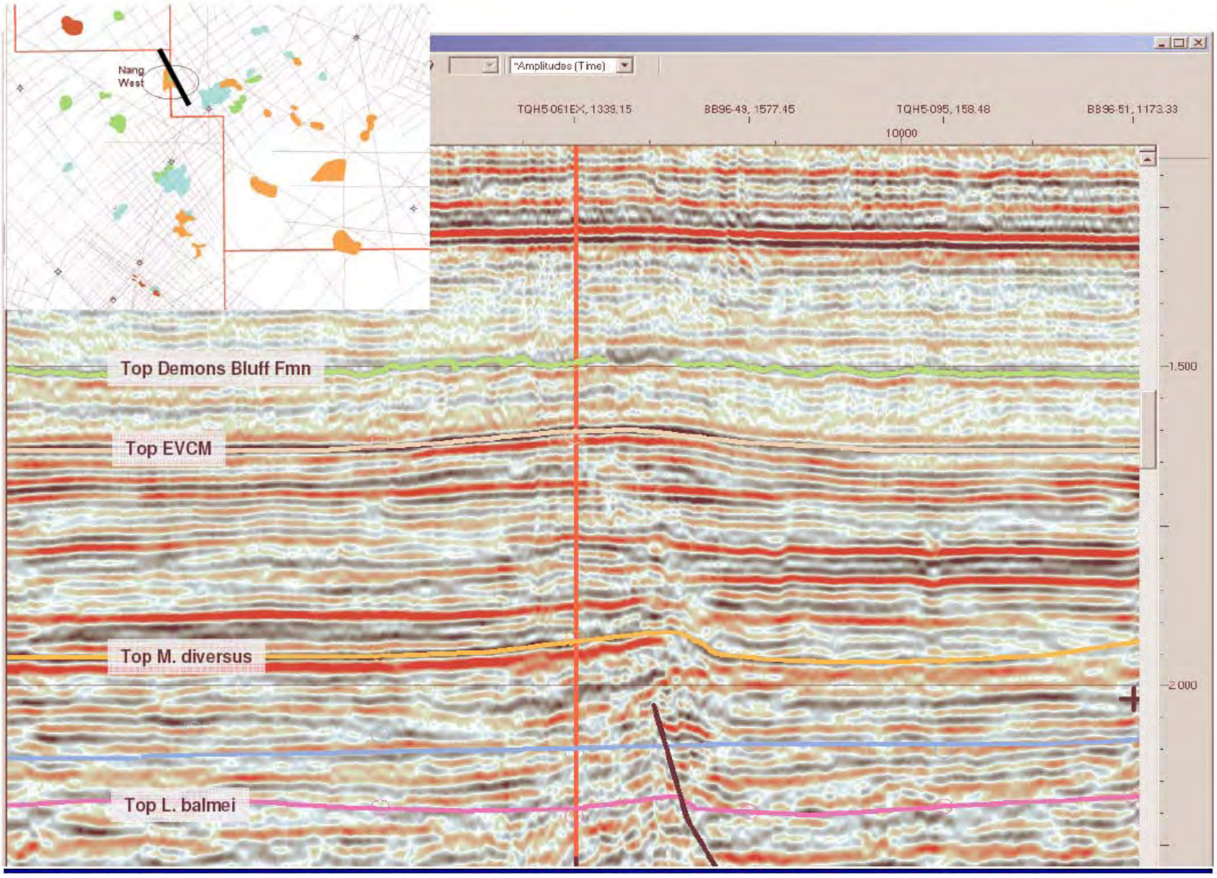

Figure 17. NW Nangkero Lead displayed on a NNW seismic strike line illustrating the increasing structural amplitude with increasing depth below the Eastern View Coal Measures seismic horizon. Inset map shows the line location.

The Leonang lead lies immediately east of the NW Nangkero Prospect, it is represented by an interpreted thick Oligocene Sandstone "Pod". The location of the interpreted pod would appear to have been defined by the creation of a down faulted or collapsed Oligocene structural low immediately to the northeast of the existing Nangkero-1 well. The feature is analogous to an almost identical "pod' encountered at the Squid-1 location to the south east.

The lead must however be considered as having a moderately high reservoir risk, and a moderate structural risk, a risk incurred through its dependency on regional velocity gradients for definition of the vertical closure of the feature.

The Squid West Fairway area lies to the southeast of the Leonang lead, this area represents a flank of one of the deeper parts of the Squid Deep.

The prospectivity of the area is enhanced by the NNE basement cross faulting of the Squid Deep.

T/38P

The Spikey Prospect (Figure 18) has been technically matured to a drillable status and has been selected by the farmin partner Beach Petroleum as its preferred drilling candidate in T/38P. The prospect lies updip and along strike from the Pelican Field area to the north.

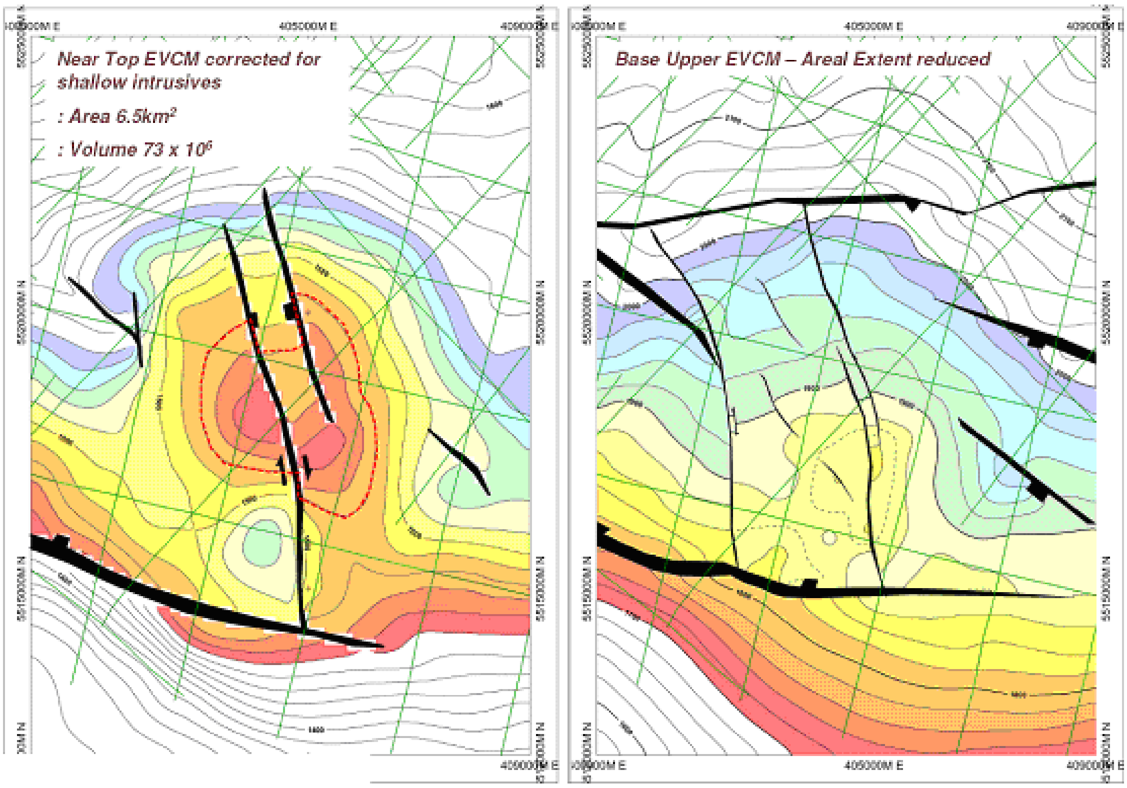

Figure 18. The Spikey Prospect displayed in map form at the near top Eastern View Coal Measures and the base of the Upper Eastern View Coal Measures seismic horizons.

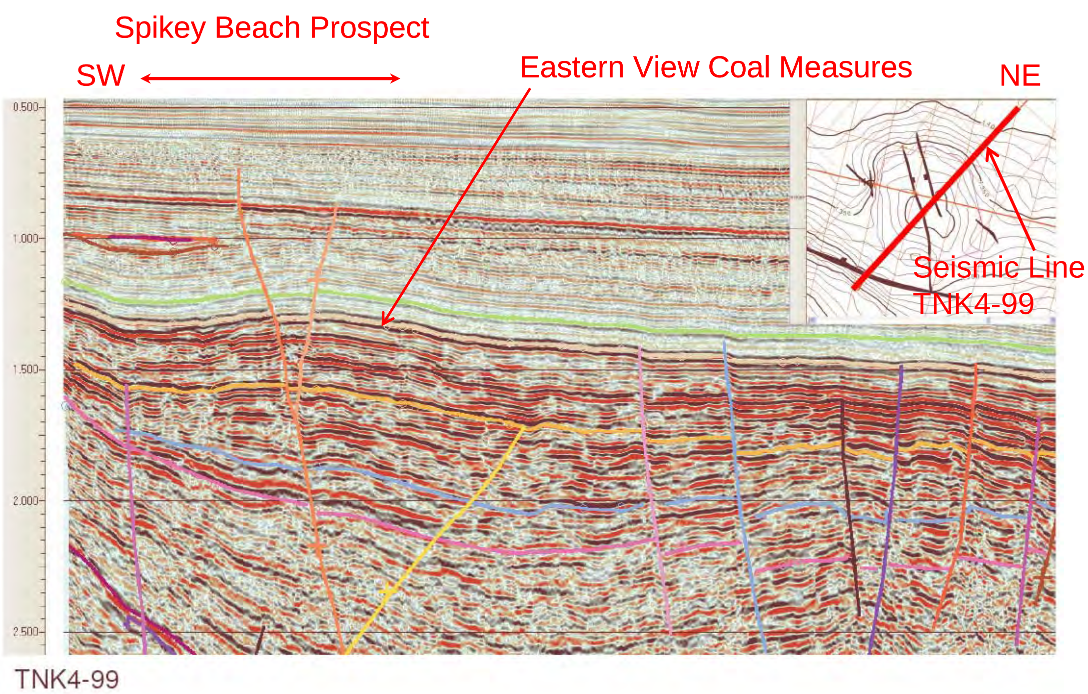

Figure 19. The Spikey Prospect displayed on seismic line TNK4-99 (see inset map) illustrating the anticlinal nature of the feature, it is located on the southwestern flank of the Pelican Trough.

The Spikey Prospect structure illustrated on the TNK4-99 seismic line above (Figure 19), reveals a late stage rollover into a southwesterly basin bounding fault margin with structural closure increasing upsection into the Eastern View Coal Measures and the overlying Demons Bluff Formation (green horizon).

The reservoir quality in the Eastern View Coal Measures section is considered to be comparable to that encountered in the Flinders-1 offset well to the north west, the hydrocarbon charge phase is considered to most likely be gas.

The Tarook Leads lie northwest of the Spikey Prospect, in an area which the farminee Beach Petroleum has excised from the remainder of T/38P and which forms the subject of their 80% equity interest in T/38P. The prospectivity identified here is considered comparable to the Pelican field structures to the southeast. The area is believed capable of receiving hydrocarbon charge from the deep Pelican Trough to the east and southeast. Reservoir potential is considered to be represented by equivalents of the fluvial sandstone channels present in the Pelican Field wells to the south east; and it is considered likely that additional reservoir potential will be found in strandplain - upward coarsening sandstones and accompanying lagoonal shales equivalent to those found at the Yolla Field to the north and east.

The Lesopoon Leads lie immediately adjacent to and south of the Poonboon-1 well location on the Nangkero-Poonboon Arch; a structural feature which separates the Squid Deep from the Pelican Trough. The Lesopoon leads have very low dips at shallower seismic horizons, their depth conversion to obtain structural maps therefore requires careful and accurate velocity data. The amplitude of vertical closure increases with depth below the top of the Eastern View Coal Measure seismic horizon, so that at the deeper level of the Top *L.Balmei* seismic horizon the vertical closure is quite pronounced. The adjacent Poonboon-1 well encountered good reservoir potential within this *L.Balmei* section. The Lesopoon lead structural closure, lies immediately updip of the Poonboon-1well location. The closure can be seismically demonstrated at the shallow Top Eastern View Coal Measure horizon, the intermediate “B” sand and “E1” level and the deeper *L.Balmei* level. The bulk of the likely reservoir volume resides in the *L.Balmei* section. Sealing potential for these horizons is considered to be low risk because of the lack of disruptive faulting of the structure.

The NW Nangkero lead has been examined in the preceding section for T/37P, the bulk of this lead resides within T/38P but will not be re-examined here.

Conclusion

The Bass Basin has been only moderately explored with relatively little recent exploration-related drilling activity. Many wells did not drill valid targets. Despite this, exploration results have been very encouraging. In this review we described numerous hydrocarbon discoveries and noted the presence of two commercial oil/gas fields. Within the Company’s permit T/38P, the Pelican wells found gas and condensate. Further encouragement is provided by the gas/condensate discovery in the Trefoil-1 well in an adjacent tenement.

There is little doubt that the Bass Basin contains sediments which provide source, reservoir and seal. It remains for the Company to undertake modern seismic surveys that will assist it to define suitable traps for oil and gas accumulations.

In the first three year permit term of the T/37 and 38P permit, the company has committed to geological and geophysical studies in each of the first two years of the Minimum Work Requirement period. In the third year of the first permit term the company intended to acquire 300 square kilometres of new 3-D data in T/37 and 200 square kilometres of 3-D seismic data in permit T/38P. In April 2007 the T/37 and 38P Joint Venture presented a rationale for a seismic variation from 3D to 2D in permits T/37P and T/38P. In July 2007, accompanied by representatives from Exoil and the farminee, a case for variation from 3D to a well in T/38P and the substitution of 300 square kilometres of seismic data with 3,000 line kilometres of seismic data in T/37P was presented to the Designated Authority. On the 9th August 2007 this third year commitment was varied by the Designated Authority to a commitment of 3,000 kilometres of 2-D seismic data. In the permit T/38P the Designated Authority agreed to a variation of the work programme to replace the 200 square kilometres of new 3-D data with one exploration well in Year 3 of the Minimum Work Programme period. This commitment will be met by the drilling of Spikey 1. Should the company so decide, it can elect to enter a second three year term in which it has indicated that it will drill one well in each permit and conduct geological and geophysical studies.

The operator for T/37P and T/38P, advised the Joint Venture that the CUEBASS08 Marine Seismic survey of some 3,660 line kilometres was completed on 18th April 2008. The survey was completed ahead of schedule due principally to favourable weather conditions during seismic acquisition.

In total, 3,660 line kilometres of full-fold seismic data in a 1x1km grid configuration was acquired in T37P and T38P. These seismic data are being processed and it is anticipated that the final processed seismic will be ready for interpretation in late 2008.

In the opinion of the author, the company has developed and committed to a satisfactory and clearly defined work programme, which is reasonable having regard to the stated objectives of the company.

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SECTION 3

THE OTWAY BASIN TENEMENTS – Vic/P61, EPP34, EPP35 & EPP36

The Company holds interests in four tenements – VIC/P61 offshore Victoria (30%) (Figure 20) and EPP 34 (15%), EPP 35 and EPP36 offshore South Australia (both 25%) (Figure 24) – and is operator of all of them.

The Otway Basin is located both on and offshore western Victoria and extends into southern Tasmanian waters and southeastern South Australia. The western, northern and eastern basin limits are defined by the extent of Upper Jurassic-Lower Cretaceous Otway Group sediments whilst the southern limit is represented by the southernmost presence of Tertiary sediments in the Hunter Sub-Basin.

The Otway region is crossed by an expanding network of gas pipelines servicing markets in Victoria and South Australia. A new interstate gas pipeline has been delivering Victorian gas to South Australia since 1 January 2004. Development of a new facility in the Port Campbell area to process gas from the Minerva field is proceeding. Further field developments and pipelines are also planned for the recent Geographe, Thylacine and Casino gas discoveries (Figure 20).

History of Exploration in the Otway Basin

Interest in the petroleum potential of the Otway Basin predates that of Gippsland. Sightings of coastal bitumen strandings led to the drilling of the first exploration well at Kingston, South Australia in 1892. The first wells in the Victorian part of the Otway Basin were drilled thirty years later in the 1920's to 1940's in the Anglesea and Torquay areas. However success in the Otway Basin did not come until 1959 when the Frome-Broken Hill consortium drilled the onshore well Port Campbell-1, which intersected hydrocarbons in the mid-Cretaceous Waarre Formation

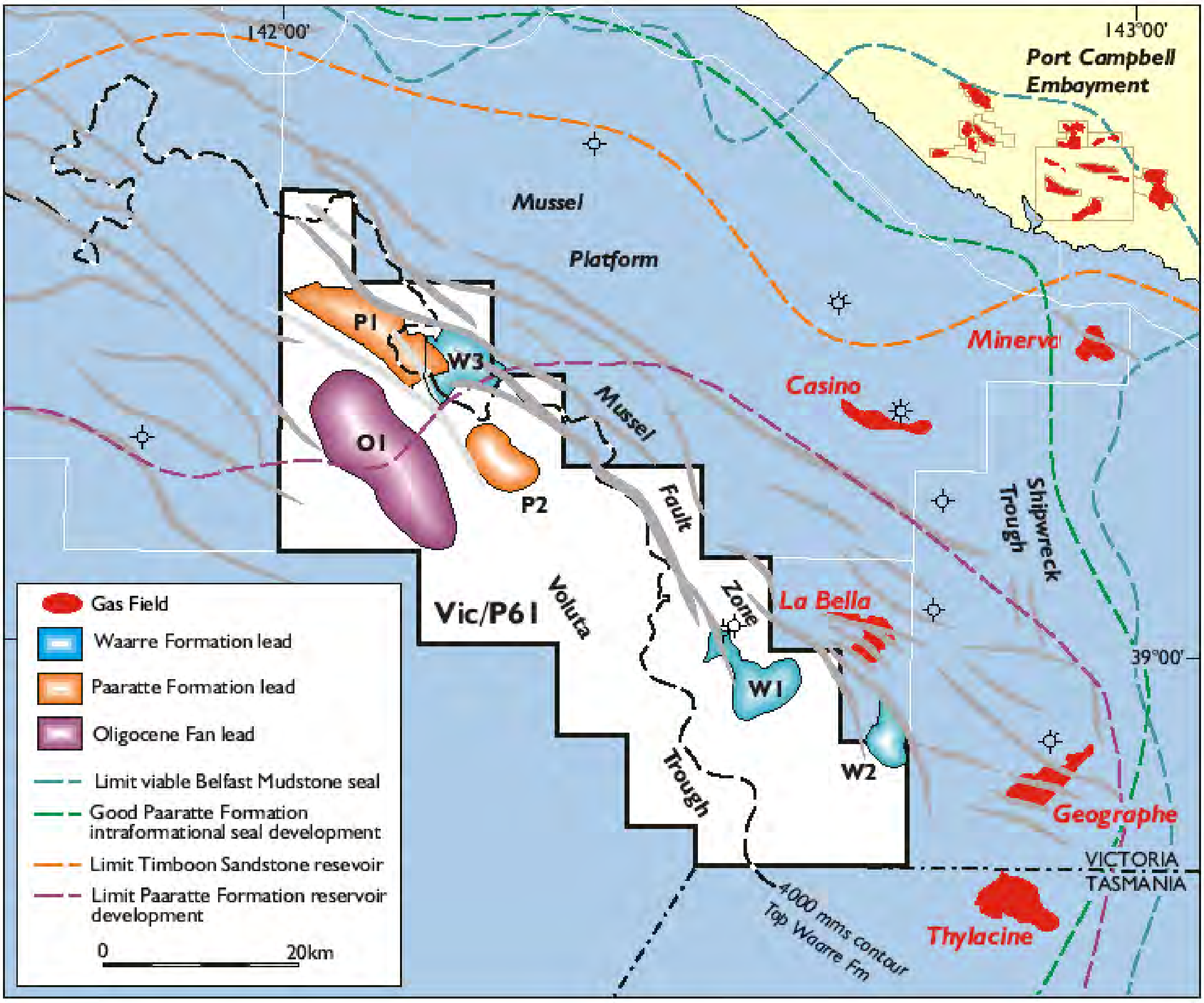


Figure 20 . VIC/P61 location map in the Otway Basin, Victoria, showing prospects and leads, well control and nearby discoveries.

A test flowed gas at a rate of 4.2 MMcfd but the discovery was deemed uneconomic at the time.

In 1966, Esso and Shell farmed into the Otway Basin and with Frome-Broken Hill, drilled 22 wells in Victoria and South Australia, located both onshore and offshore. This exploration effort by the consortium was anticipating the success obtained in the Gippsland Basin, their efforts were largely unrewarded with only minor gas encountered at Pecten-1.

Most companies had withdrawn by 1976, relinquishing their permits, discouraged by the lack of commercial success.

Following a period of limited exploration, Beach Petroleum discovered gas in 1979 at North Paaratte-1, only 3 kilometres northeast of Port Campbell-1. Encouraged by this gas discovery, offshore permits were bid for and subsequently awarded to groups led by Esso, Phillips, and Ultramar. Although this exploration effort also ultimately proved unsuccessful, small gas discoveries were made onshore by Beach Petroleum at Grumby-1 and Wallaby Creek-1, which produced from the Waarre Formation. Enough of this gas was subsequently proven for commercial production to commence in 1987, supplying the regional centres of Portland and Warrnambool.

In 1992, offshore permits VIC/P30 and VIC/P31 were awarded to BHP Petroleum (BHPP), the company drilled two discovery wells at Minerva-1 in 1993 and La Bella-1 in 1994. After drilling an additional five wells with only minor gas shows, BHPP relinquished the permits in 1997. The Minerva and La Bella fields were however, retained under retention leases.

Since 1998, there has been a resurgence in exploration activity in the Otway Basin largely driven by new geological ideas, technological advances and an opening gas market in both Victoria and South Australia. A major exploration program by the Woodside joint venture, which included the acquisition of modern 3D seismic, resulted in the large Geographe and Thylacine gas discoveries. Offshore, Santos discovered the Casino gas field in 2002 and most recently, the Henry gas field in 2005. Onshore Santos' exploration program, again aided by 3D seismic data, resulted in the discovery of three new gas fields. Elsewhere in the basin, a high level of exploration activity persists with other groups currently at various stages in the execution of their exploration programs.

Regional Geology

The Otway Basin is a NW-SE striking rift to passive margin basin that extends from Cape Jaffa in South Australia to the northwestern coast of Tasmania. It belongs to a series of basins that developed as a result of Gondwanaan break-up and rifting which resulted in the separation of Antarctica from Australia and the development of the Southern Ocean. The sedimentary section in the basin ranges from the Late Jurassic to Recent and covers an area of 150,000 square kilometres, 80% of which is located offshore.

Tectonic Development

The Otway Basin's regional structural style is similar to oblique-rift analogue models suggesting that basin architecture was profoundly controlled by a basement fabric.

The Early Jurassic phase of rifting in the Otway Basin is characterised by development of a series of E-W trending half-grabens controlled by steep north-dipping extensional faults. Later Early Cretaceous rifting was expressed by half-graben development controlled by NE and WNW trending faults which dip steeply towards the NW and NNE respectively. The eastern Otway region is bounded to the west by the Moyston Fault Zone and includes within it the Colac Trough, the Otway Ranges and the Torquay Sub-basin.

Subsequent Late Cretaceous rifting created the major structural elements exhibited to the present day, which include the Voluta Trough, Mussel Platform, Prawn Platform and the Shipwreck Trough (Figure 20). These structures were later modified during Tertiary passive margin development and by Late Tertiary compression. This history contrasts strongly with the basins east of the Sorell Fault System, these easterly basins namely the Torquay Sub-basin, the Gippsland and the Bass basins have remained as failed rifts within an intracratonic setting.

Stratigraphy

Basin fill of the Otway Basin is subdivided into five stratigraphic groups: the Otway, Sherbrook, Wangerrip, Nirranda and Heytesbury groups, each separated by clearly recognisable unconformities (Figure 21). The Upper Jurassic to Lower Cretaceous Otway Group was deposited during early rifting, while the Upper Cretaceous Sherbrook Group was established during a second rift phase. The three Tertiary groups were deposited on a divergent passive margin as southwest advancing marine shelves. They comprise major cycles of marine transgression and regression separated by unconformities that represent periods of tectonism.

Petroleum Potential:

Successful petroleum exploration depends upon the presence of and effective interaction of a number of natural variables to produce a commercially productive petroleum system, these variables are examined below:

(i) mature source rocks,

(ii) reservoir,

(iii) seal and

(iv) hydrocarbon traps.

(i) Source Rocks and Maturation

The Lower Cretaceous Otway Group is recognised as providing the source for the majority of gas and minor oil discoveries in the Otway Basin. Geochemical studies have identified the Eumeralla Formation as the predominant source for gas and minor oil discoveries in the Port Campbell/Shipwreck Trough region. Major source intervals comprise two coal-rich horizons; one of Aptian age (C*. notensis* biozone) near the base of the Eumeralla formation and the second of Lower Albian age (*C. striatus* biozone) in the middle of the formation. Both sequences are about 200 metres thick and consist of multiple 2 - 3 metre seams with intercalated mudstones that are rich in disseminated organic matter. Well control and seismic data indicate that these sequences are extensively developed across the basin, they have excellent source rock potential for gas and light oil.

The hydrocarbon potential of the Upper Cretaceous Sherbrook Group is distinctly greater in areas basinward of the continental slope, where the section is thicker and more deeply buried and where maturation has been sufficient for hydrocarbon generation. Possible source intervals are present in the Belfast marine mudstones and the underlying Waarre Formation, where they contain marine to coastal plain sediments. This source possibility is of particular relevance to VIC/P61, which straddles the slope break and the Tartwaup-Mussel Fault zone.

(ii) Reservoir

The mid-Cretaceous Waarre Formation is the major productive reservoir interval in the Victorian part of the Otway Basin. Producible gas has been encountered in sixteen onshore fields in the Port Campbell area, these fields range in size from Skull Creek (2.2 Bcf GIP) to Iona (40.3 Bcf GIP). In the offshore Shipwreck Trough, the Waarre Formation and overlying Flaxmans/Lower Belfast formations host major gas accumulations in the Minerva,

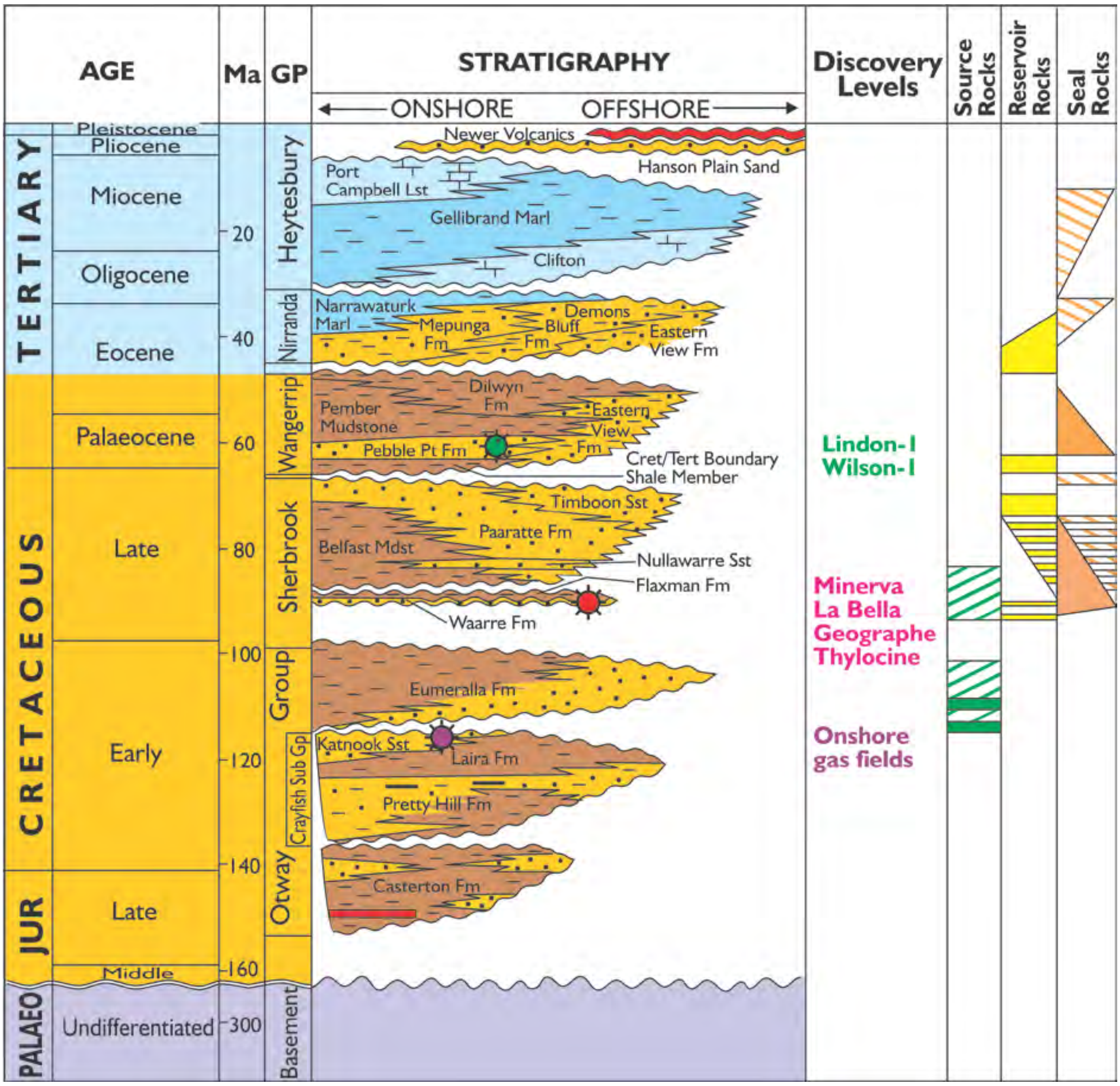


Figure 21. Generalised stratigraphy and petroleum system components of the Otway Basin in Victoria and South Australia.

La Bella, Casino, Henry, Geographe and Thylacine fields. Except for La Bella, all are currently being developed or considered for development. Gas-in-place is estimated at 1,300 Bcf in Thylacine and 465 Bcf in Geographe. Minerva contains 425 Bcf, La Bella 210 Bcf and Casino some 300 Bcf GIP.

The uppermost Cretaceous (Maastrichtian) Paaratte Formation and Timboon Sandstone also contain reservoir quality sandstones represented by multiple progradations of delta lobes in delta front and lower delta plain environments. As yet these two formations remain unproductive.

The Tertiary (Palaeocene) Pebble Point Formation may also provide an attractive exploration target. This formation was not considered an exploration target until the recording of a live oil show in the unit at the onshore Curdie-1 well drilled in 1982 and located within the Port Campbell Embayment. Since then, small quantities of oil have also been recovered from Lindon-1 and Fahley-1, while residual oil was found at Wilson-1. However, poor reservoir development (high porosity up to 25% but low permeability) in these wells is due to the presence of chamositic clay in the rock matrix which prevented significant oil flows on test. Play validity depends on the presence of better reservoir development elsewhere in the basin.

(iii) Seal

The sealing units for the Port Campbell and Shipwreck Trough gas fields are comprised of marine intraformational claystones of the Flaxman Formation and the thick regional seal represented by the Belfast Mudstone. Both units are extensively developed and are thickest in the offshore part of the basin. Seal formation potential within the Paaratte Formation and Timboon Sandstones is characterised by intraformational mudstones. The late Maastrichtian/earliest Paleocene Kate Shale may also provide seal potential. The Palaeocene Pebble Point Formation is sealed by the seaward thickening Pember Mudstone.

(iv) Traps

The gas accumulations in the Port Campbell-Shipwreck Trough area are principally reservoired in the Waarre and Flaxman formations and Belfast Formation equivalent Turonian-Santonian slope fan sandstones. The traps comprise faulted anticlines and tilted fault blocks of Late Cretaceous age that are often slightly modified by Late Tertiary compression. Several other play types involving different reservoir objectives have also been identified and are summarised below.

1. Crayfish Sub-Group sandstone plays (including Pretty Hill Sandstone) in Cretaceous fault blocks sealed either intraformationally or by a Eumeralla Formation top seal.
2. Waarre/Flaxman Formation sandstone plays in folded/faulted anticlines sealed by the Belfast Mudstone.
3. Turonian–Santonian slope fan plays (Belfast Formation equivalent) in folded/faulted anticlines sealed by the Belfast Mudstone.
4. Intra-Paaratte Formation plays in Upper Cretaceous fault blocks sealed by the Belfast Mudstone.
5. Top Paaratte and Timboon formation plays in eroded Late Cretaceous fault blocks sealed by Wangerrip Group mudstones.
6. Wangerrip and Nirranda Group stratigraphic plays.
7. Oligocene lowstand fan stratigraphic plays.

VIC/P61 VICTORIA

Introduction

VIC/P61 is located in the offshore Otway Basin some 50-60 kilometres southwest of Port Campbell (Figure 20). Exoil holds a 30% interest in the permit and is permit operator. The tenement comprises 30 graticular blocks covering 1,874 square kilometres. The majority of the area lies within water depths of 100 to 500 metres with the shoreward part of the platform area lying at depths of less than 100 metres and the deepest basinal part locally exceeding 1,000 metres. Its eastern boundary is close to gas discoveries at La Bella, Geographe, Thylacine, Casino and Henry.

Previous Exploration

During the initial phase of offshore exploration in the late 1960's, the VIC/P61 tenement was part of PEP 40 and PEP 49, then operated by Hematite (later BHP Petroleum Pty Ltd). Following a farm-in by Esso, Nautilus-1 was drilled in 1968 penetrating down to the Upper Cretaceous Sherbrook Group. Subsequently the area experienced a hiatus in exploration until 1982 when Triton-1 was drilled by Esso, the well penetrating deeper into the Waarre Formation (Australian Government, Department of Industry, Tourism and Resources, 2004).

In the early 1990s, the permit was part of VIC/P31, awarded with adjacent permit VIC/P30, to BHP Petroleum in 1992. At the time the two permits comprised much of the Victorian offshore part of the basin. The company's exploration program primarily focused on the shallow marine and shelf portions of its permits and only limited seismic covered the shelf-break and continental slope that comprises two thirds of the area of VIC/P61 (Figure 20).

After drilling seven exploration wells and only achieving success with the Minerva and La Bella gas discoveries, the BHPP joint venture terminated its Otway Basin exploration program in 1996 and withdrew from the two permits. Retention leases were kept over both gas fields then deemed sub-economic. In 2002 a production licence over the Minerva area (VIC/L22) was awarded to BHP Billiton and Santos as a prelude to the field's development.

Well Control

Nautilus-1 and Triton-1 are the only wells drilled in VIC/P61. Both are located in the southeast of the permit on the modern shelf edge on the platform behind the Tartwaup-Mussel Fault Zone (Figure 20). Additional well control is provided by La Bella-1, Mussel-1 and Conan-1 to the north on the platform as well as by the recent gas discoveries at Thylacine, Geographe and Casino.

Geographe-1 and Thylacine-1 were drilled by Woodside in 2001, as part of an ongoing joint venture with Origin and CalEnergy. Both wells were commercial gas discoveries that have since led to full field production in 2007. The wells were drilled after they were identified by the detailed mapping of the Investigator 3D seismic survey. Sandstone reservoirs in the Waarre Formation and Belfast equivalent are preserved, with excellent reservoir qualities.

Seismic Data

Numerous seismic surveys extend into the VIC/P61 permit. They consist entirely of 2D data and vary in quality and extent. The most recent data was acquired in 2001 by Fugro MCS as part of a larger Otway/Sorell regional seismic program. The only 3D surveys in the region are the 1999 Investigator 3D acquired over Geographe and Thylacine and the 1994 Minerva 3D Survey, which was acquired to the north. Seismic coverage in the permit itself is greatest over the northern flank, which covers the platform area, but seismic coverage is poor over much of the southern part of the permit, south of the Tartwaup-Mussel Fault Zone.

Petroleum Prospectivity

The palaeogeographic location of VIC/P61 covering inner to outer shelf regions of the Otway Basin, provides the setting for a variety of petroleum plays, ranging from fluvio-deltaic to shelf-break/slope fan (Figures 20 and 21).

The principal play types within the permit together with identified leads are:

1. Waarre/Flaxman Formation sandstone plays in folded/faulted anticlines sealed by the Belfast Mudstone (Leads W1, W2 in Figure 20, 21 and Figure 22.
2. Turonian–Santonian slope fan plays in folded/faulted anticlines sealed by the Belfast Mudstone (Leads W1, W2 in Figure 22).
3. Intra Paaratte Formation plays in Late Cretaceous fault blocks sealed by the Belfast Mudstone (Leads P1, P2 in Figure 20 and Figure 23).
4. Top Paaratte Formation plays in eroded Late Cretaceous fault blocks sealed by Wangerrip Group mudstones (Leads P1, P2 in Figure 20).

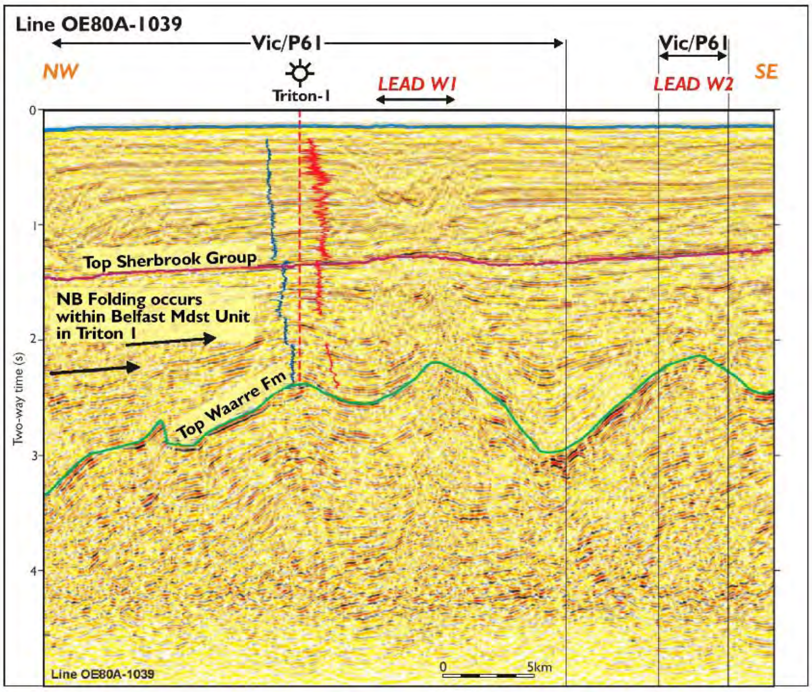


Figure 22. Seismic section OH91-103 showing Waarre leads W1 and W2 in Vic/P61.

The Late Cretaceous Waarre Formation represents the primary target on the marine shelf, but it is downthrown to depths of below 3,000 metres south of the Tartwaup-Mussel Fault Zone; this interval is only regarded as a secondary target over the southern part of VICP/61.

A number of shallow plays have been identified in the northwest of the permit, the principal one being Paaratte sandstones sealed intraformationally and/or by the regionally extensive Kate Shale as shown in Figure 20 (Australian Government, Department of Industry, Tourism and Resources, 2004). Additional plays include as yet untested stratigraphic plays within outer shelf/slope sediments likely involving sandy facies of the Pebble Point Formation sealed by the Pember Mudstone or Oligocene lowstand fans (Geary and Reid, 1998).

Conclusion

VIC/P61, from this review, contains all the required elements for oil and gas generation and accumulation. Sandstone reservoirs are widely distributed and are commonly associated with seal lithologies. Although the offshore Otway Basin has, to date, yielded mainly gas with only minor condensate and oil, geochemical modelling has demonstrated the potential of the Late Cretaceous marginal marine and lower coastal plain source rocks to generate significant quantities of liquid hydrocarbons including oil. This section is likely to be well developed both within and down-dip of the permit at suitable depths for maturation and generation.

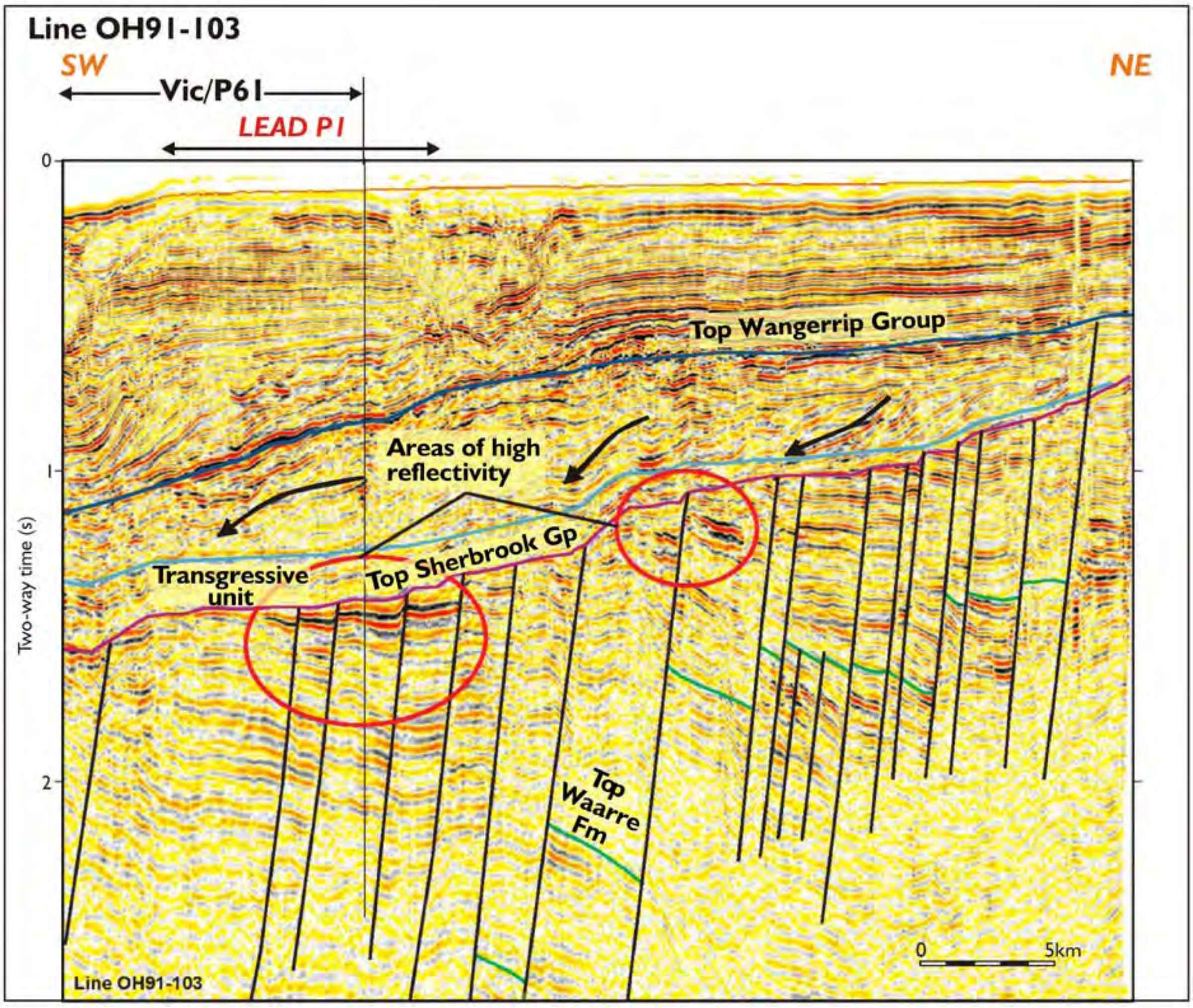


Figure 23. Seismic section OH91-103 showing Paaratte lead P1 in Vic/P61.

The permit offers a variety of exploration targets while the recent gas discoveries in adjacent acreage and their proposed development provide encouragement for exploration.

In the first three year permit term of the VIC/P-61 permit, the company has committed to acquire 760 kilometres of existing 2-D seismic data and to reprocess and perform preliminary investigative mapping of the permit. The company will also acquire 450 square kilometres of 3-D seismic data and process it in Year 2 of the Minimum Work Programme period. The third year of the programme in the Minimum Work Requirement period requires the the company interpret the 3-D data set and make preparations for drilling and drilling.

Should the company so decide, it can elect to enter a second three year term in which it has indicated that it will drill one well and conduct geological and geophysical studies and make a reassessment of the permit.

On the 6th June 2007 the Company received a suspension of the work programme which would see the Year 2 conditions undergo a 10 month suspension from 7th February 2007 to 7th December 2007. The term of the permit would therefore be extended from 7th February 2011 to 7th December 2011. The Company has recently sought an indefinite suspension and extension of Vic/P61 following the inability to obtain environmental approval for the plannned acquisiton of 1,000 kms of new 2D seismic, which was to compliment the acquisition of the existing 760 kms 2D data and as a forerunner to assist the siting of the proposed 3D seismic program.

In the opinion of the author, the company has developed and committed to a satisfactory and clearly defined work programme, which is reasonable having regard to the stated objectives of the company.

EPP 34, EPP 35 and EPP 36 SOUTH AUSTRALIA

Introduction

Permits EPP34, EPP 35 and EPP 36 are located in the western Otway Basin, offshore South Australia. EPP 34 contains 76 offshore graticular blocks and covers an area of 4,850 square kilometres. EPP 35 consists of 32 offshore graticular blocks covering an area of 1,907 square kilometres. Permit EPP 36 consists of 68 offshore graticular blocks covering an area of 4,267 square kilometres. Exoil holds a 15% interest in the permit EPP 34, a 30% interest in permits EPP 35 and 36, it is the operator in all three permits. The three permits lie approximately 6 kilometres off the South Australian coast approximately 200 kilometres southeast of Adelaide (Figure 24). The permits overlie the continental shelf and mid-continental slope with water depths increasing in a southwesterly direction from less than 50 metres to over 2,000 metres. EPP 36 the most southerly disposed of the permits, has water depths in excess of 200 metres to greater than 2,500 metres.

Previous Exploration

All three permits have only been lightly explored with a relatively sparse coverage of vintage 2D seismic data, with 19,719 kilometres of 2-D data being available in the Otway Basin and just 371 square kilometres of 3-D data in the entire basin (South Australian Section). There are a total of 10 offshore wells in the basin. Only two wells have been drilled within the permit EPP 34, they are Chama-1A and Copa-1. The target for both wells was the Lower Cretaceous Crayfish Subgroup (Figure 21). Chama-1A reached its objective in the lower part of the Crayfish section, but despite encouraging shows, formation tests did not recover significant hydrocarbons. Copa-1 stopped short in the Crayfish Sub-Group and did not reach its Pretty Hill Sandstone target. EPP 35, the smallest of the Otway permits, has received the most exploration activity in the area, a process which resulted in the discovery of the Troas gas field in 1993. The well encountered an 1,140 metre gross gas column, containing 98 metres of net gas in sandstones of the Crayfish Group, with an average porosity of 13% and possessing an average gas saturation of 55%. The concentration of carbon dioxide within the predominantly hydrocarbon gas recovered from two cased hole RFT's, the first at 2,698 metres, the second at 2,966 metres, indicated an increase in concentration from 4 to 17%. It is not known whether this range indicates an increase of carbon dioxide with depth or simply variation between separate sandstone packages. The first well within the boundary of the present day EPP 35 permit was Crayfish-A1 drilled in 1967 - on the Crayfish Platform. It was poorly located to receive charge from Eumeralla Formation source rocks, but demonstrated the presence of good quality sandstones in the Pretty Hill Sandstone Formation. The well reached a total depth at 3,196 metres with some gas indications. Neptune-1 was drilled in 1973, it reached a total depth of 2,436 metres with no apparent hydrocarbon shows but with good quality reservoir in Pretty Hill Sandstones. Sophia Jane-1 was drilled in 1995 it was plugged and abandoned at a depth of 2,340 metres with some oil and gas indications. Trumpet-1 was drilled in 1973 to a depth of 2,256 metres, the well was plugged and abandoned with no hydrocarbon shows encountered.

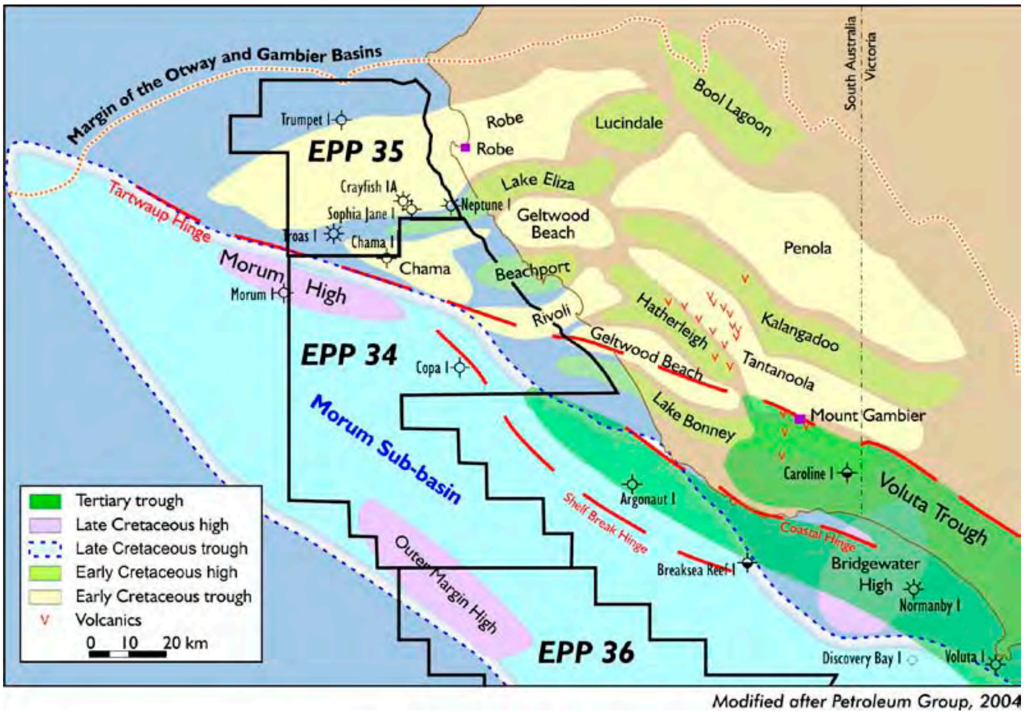
Within the present area of EPP 36 there are no existing exploration wells. In the adjacent and nearshore permit there are two wells, Argonaut-1 drilled in 1968 to a depth of 3,707 metres which was plugged and abandoned with no hydrocarbon shows. The second well Breaksea Reef-1, was drilled in 1968 and later plugged and abandoned at a depth of 4,468 metres with gas shows and oil indications.

Petroleum Prospectivity

The permits EPP34, 35 and 36 are considered to contain mature source rocks, multiple reservoir units and the development of regional and intra-formational seals.

The anticipated principal plays within the permit are:

1. Crayfish Sub-Group sandstone plays in Cretaceous fault blocks with seal provided by the Eumeralla Formation, in both a top seal and an intraformational setting.
2. Waarre Formation sandstone plays in Cretaceous fault blocks regionally sealed by the Belfast Mudstone
3. Additional potential for structural and stratigraphic traps is considered to be present in the Tertiary section.
4. In the deeper water extensions of EPP34 and 36, potential exists for overpressured submarine slope-fan traps encased within the Belfast Mudstone. The interpreted deep water depositional nature of the section within EPP36 may offer the possibility for excellent reservoir potential and for stacked plays within thick Upper Cretaceous section. The interpreted marine influence in sedimentary environments which dominated the past accumulation of rocks in EPP 36 may also allow for the consideration of additional marine influenced source rock in deep water. A noteworthy feature of EPP34 and EPP 35 is the interpreted presence of Waarre Formation sandstones at drillable depths. The Waarre Formation provides the major reservoir unit for gas fields in the Otway Basin farther to the east in the Victorian Otway Basin waters. Although not the principal target of Chama-1 and Copa-1, the two wells drilled in the EPP 34 permit, both encountered good reservoir properties in Waarre sandstones. Effective regional seal to the Waarre is provided by the overlying Belfast Formation which is some 500 metres thick in this permit.



Figure

24. EPP 34, EPP 35 & EPP 36 location map in the Otway Basin, South Australia, showing structural elements and well control.

EPP 35 contains the existing Troas field structure, which comprises a tilted fault block (Figure 25a), constrained to the north east and northwest by dip closure and towards the south by fault closure (Figure 25b). Log interpretation indicated that the well intersected a total 1,150 metres of gross hydrocarbon bearing section from a depth of 2,350 metres below kelly bushing to the total depth at 3,506 metres below kelly bushing (98 metres of net gas sandstone with an average porosity of 13%, and an average gas saturation of 55%). Recent interpretation work performed on the well and seismic data may indicate that additional resources within the Pretty Hill Sandstone Formation section underlie the known hydrocarbon pool intersected at the Troas 1/1ST well location (Figure 25a). In addition, there may be possible reserves associated with fault blocks that form the southern margin of the Crayfish Platform or the down-thrown fault blocks immediately to the south of the main Troas accumulation. Substantial potential reserves may be intersected by drilling stratigraphically deeper than those formations encountered in the existing Troas $1/1^{ST}$.

There is a further possibility of encountering potential reserves by drilling structurally updip of the Troas-$1/1^{ST}$ location, therefore intersecting updip extensions of the gas charged sandstones encountered at the original Troas-$1/1^{ST}$ location (Figure 25a).

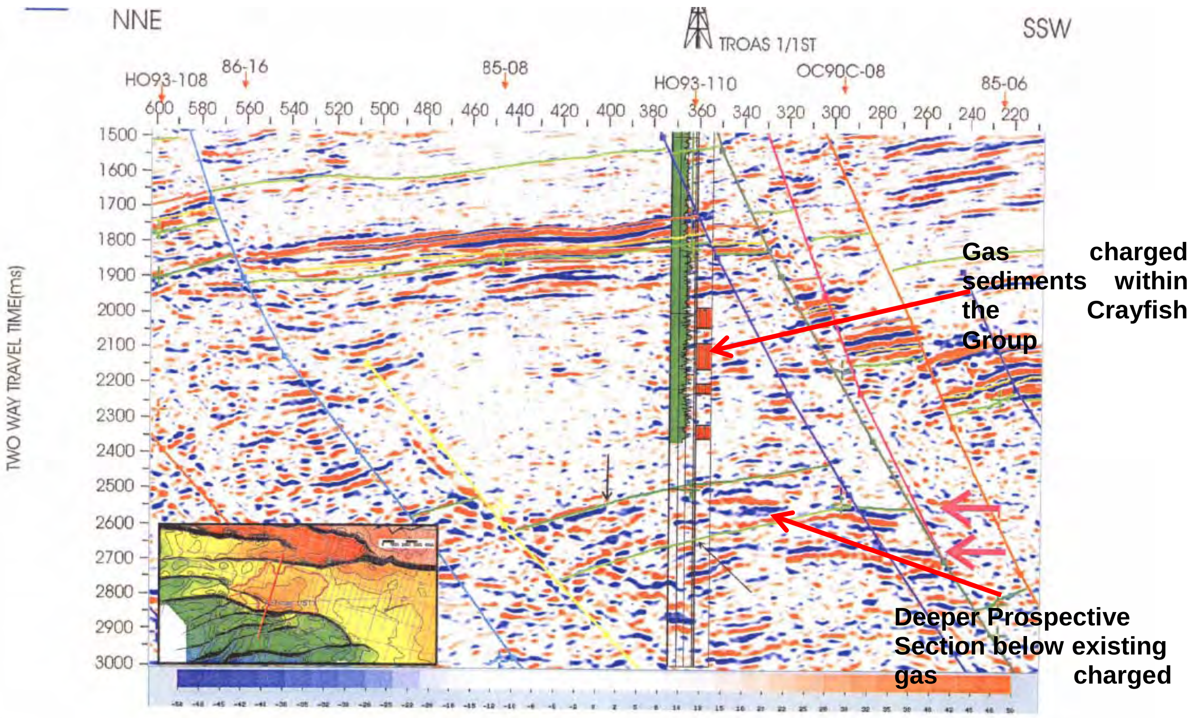


Figure 25a. Permit EPP 35 - Seismic Line OC90C-23 through Troas-1/1^ST well location showing location of the gas charged section within the Crayfish Group, and the IntraCrayfish and Top Pretty Hill seismic horizons.

Warm colours indicate shallow depths-colder colours (blues & greens) Deeper section

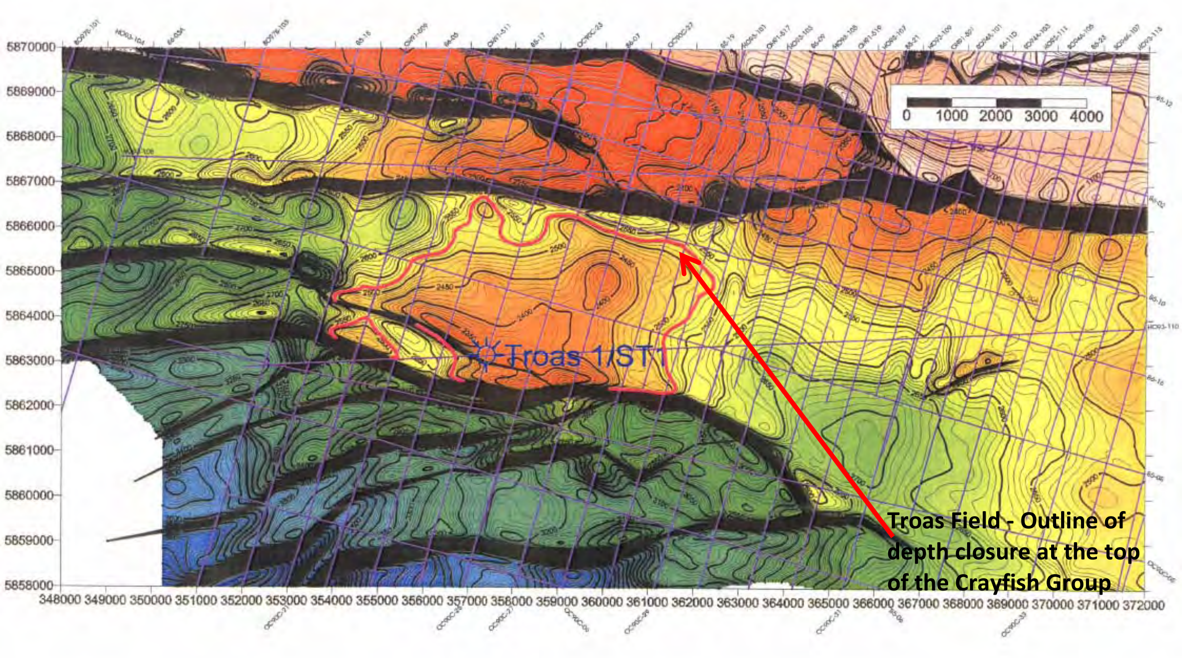


Figure 25b. Permit EPP 35 – Top Crayfish Group – Depth Structure Map – Troas Field, showing the outline closure at the top of the gas charged section in the Crayfish Group.

Of particular relevance to permits EPP 34 and 36 are possible sea surface hydrocarbon seeps both within and to the south of the permits, these seeps have been identified by an airborne Synthetic Aperture Radar (SAR) survey conducted by Infoterra and Geoscience Australia.

Conclusion

The Otway Basin permits EPP 34, 35 and 36 would appear to contain all of the required elements of a functioning petroleum system. Waarre Formation reservoirs appear to be widespread and are not deeply buried, thus are likely to retain reservoir quality sandstones. The data obtained by Troas-1, demonstrates the potential of the Crayfish Sub-Group to host a significant gas accumulation in multiple reservoir sands. Further testing is required to assess the commercial producibililty of the Crayfish sandstones.

The petroleum potential of EPP34 and EPP35 is complemented by their proximity to both the Victorian and South Australian gas markets and the increasing demand for gas in south-eastern Australia. The permits are believed to be well located to allow any gas discovery to tie into the gas pipeline network, which has now been established across the onshore Otway Basin.

In the first three year term of the EPP 34 permit, the company committed to acquire available open file reports, existing seismic and well data and to synthesize and integrate this information with mapping. The company agreed to acquire and reprocess not less than 1,500 kilometres of open file seismic data, and also acquire and process 600 line kilometres of new 2-D seismic data as an infill to the existing seismic data set. This latter commitment, to have been performed in the final year – Year 3 of the Minimum Work Requirement programme, has been the subject of a suspension of work conditions by the Designated Authority. This suspension will now mean that Year 3 runs from 25th March 2007 to 24th June 2008 inclusive. The term of exploration permit EPP 34 will now expire on 24th June 2011. The Company met this commitment as a result of the acquisition of the 1,100 line kilometre Trocopa 2D seismic survey, together with the reprocessing of more than 1,500 kilometres of older data.

Should the company so decide, it can elect to enter a second three year term in which it has indicated that it will drill one well and and commit to acreage analysis and review well results

In permit EPP 35 the company has committed to a programme consisting of a phase of Geotechnical Studies. It has also committed to reprocess 1,200 kilometres of 2-D seismic data and perform further Geotechnical Studies. It will also acquire 325 square kilometres of a 3-D seismic survey in the first three year permit term. Should the company so decide it can elect to enter a second three year term in which it has indicated it will drill one well and perform further Geotechnical Studies. It is presently planned for a 325 square kilometre survey to be acquired in 2008/2009.

In the first three year term of the EPP 36 permit, the company has committed to perform a programme of Geotechnical Studies and to acquire a 1,100 kilometre survey of 2-D seismic data. It is presently planning the acquisition of this survey. Should the company so decide, it can elect to enter a second three year term in which it has indicated that it will drill one well and perform a further programme of Geotechnical Studies.
In the opinion of the author, the company has developed and committed to a satisfactory and clearly defined work programme, which is reasonable having regard to the stated objectives of the company.

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SECTION 4

THE BROWSE BASIN TENEMENTS – WA-332-P, WA-333-P & WA-342-P

Introduction

The Browse Basin region off the coast of Western Australia has a 40 year history of exploration. It is an established petroleum sub-province and it forms a part of the extensive series of continental margin sedimentary basins that, together, comprise the world class North West Shelf hydrocarbon province, located offshore Western Australia. The Browse Basin has been host to a series of major gas, gas condensate and oil discoveries which began with the 1971 discovery at Scott Reef No. 1. The Scott Reef discovery predated the discovery of North Rankin and the Gwydion gas fields in the Carnarvon Basin by some months.

The first discovery at Scott Reef-1 was followed, over the years, by major discoveries at Brewster, Caswell, Brecknock, Brecknock South (renamed Calliance) and Echuca Shoals. In a later phase of exploration important discoveries were made at Gwydion and Cornea. The latest major discoveries in the Browse Basin, commencing in 2000, have been made at Dinichthys, Titanichthys and Gorganichthys by INPEX Browse Ltd. The latter, a giant 556.02 MMbl condensate and 10.7 Tcf gas field (now renamed Ichthys Field), which lies approximately 50 kilometres to the west of the WA-332-P, WA-333-P, and WA-342-P group of blocks, which are the subject of this report. More recently, in 2007 and 2008, Shell and INPEX have made significant gas discoveries in WA-371-P and WA-344-P with the Prelude-1/1A and Mimia-1 wells respectively.

The permits WA-332-P, WA-333-P, and WA-342-P, in which Exoil's wholly owned subsidiary holds a 35% interest, are illustrated in Figure 26 and lie up dip of the major central Browse Basin gas, gas/condensate and oil discoveries. For the most part they lie on trend with the basin margin oil and gas accumulations at Gwydion and the recently discovered Cornea Field wells.

The Crux Field lies 40 kilometres due north of WA-342-P. The reservoired natural gas was sold to Shell in early 2007, but not the condensate which will be stripped out, sold and the gas recycled. The contingent resource identified by Nexus the operator, is estimated at 55 million barrels. A development decision is expected in the fourth quarter of 2008.

The Scott Reef fields (now renamed Torosa Field) are now the subject of joint venture development studies to examine the possibility of building two LNG processing trains, with capacity to produce up to 7-14 million tonnes per year. An agreement has already been reached with PetroChina to supply 2-3 Mtpa in future. A FEED study has been earmarked for 2009, for this project.

Background

The permits WA-332-P and WA-333-P are presently lightly explored. There is one well on the boundary of WA-332-P (Prudhoe-1), one well in WA-333-P (Rob Roy-1), and a total of fourteen wells in WA-342-P, mostly associated with the Cornea Field.

To date, in the Browse Basin, 86 exploration wells (79 in West Australian waters) had been drilled, yielding 25 discoveries and thus a technical success rate of 29%.

Structural Controls

Permits WA-332-P, WA-333-P and WA-342-P, reside wholly within the Browse Basin.

The Browse Basin is composed of a number of important structural elements (Figure 26). There are four major sub-basins in or adjacent to it, the Caswell, Barcoo (or Rowley Sub-basin), the Scott and the Seringapatam Sub-basins. Inboard from the sub-basins there are a series of shallower basement elements, the Prudhoe Terrace, being an intermediate structural terrace down-thrown from the Yampi Shelf and its extension to the south, the Leveque Shelf.

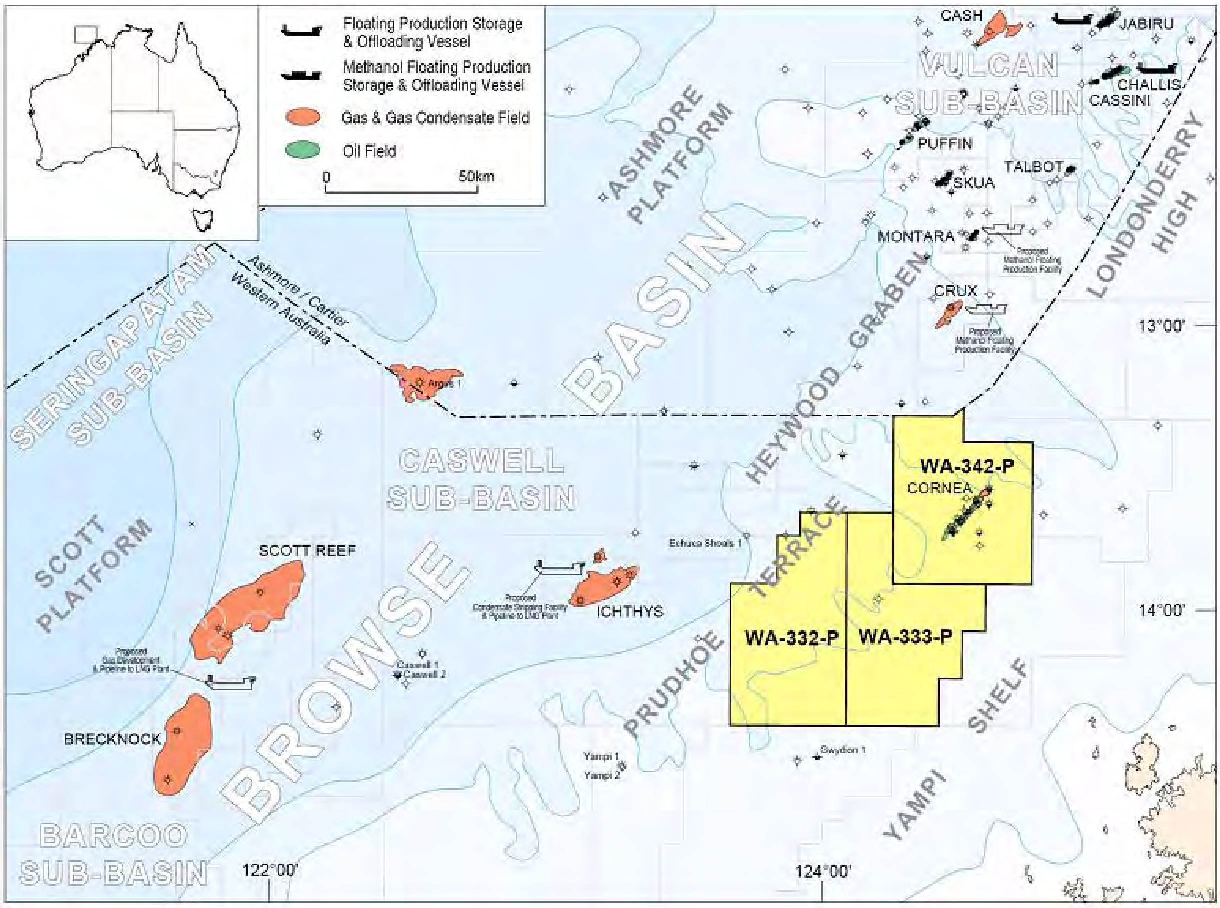

Figure 26. Structural elements map Northern Browse Basin.

The Caswell Sub-basin is approximately 200 kilometres wide and is considered to contain the source “kitchen” areas for the generation of a considerable bulk of Browse Basin hydrocarbons. Permits WA-332-P, WA-333-P and WA-342-P principally occupy sectors of the Prudhoe Terrace and the Yampi Shelf. The Caswell Sub-basin and its narrow rifted extension, the Heywood Graben, extends through the vicinity of the Heywood-1 well location and continues north-eastwards where it eventually joins the Vulcan Sub-basin.

The oil and gas discoveries at Gwydion-1 and Caspar-1 lie approximately 10 kilometres to the south of WA-332-P and WA-333-P, on the Yampi Shelf. The major gas and condensate discoveries in the Brewster-1A, Dinichthys-1 Gorgonichthys-1 and Titanichthys-1 field area (now termed the Ichthys Field), lie approximately 45 kilometres from the western boundary of WA-322-P. This trend of major discoveries passes north-eastwards into WA-371-P and would appear to be connected to the discovery at the Prelude-1 location.

The north-easterly trend of the major faults and lineaments present in the eastern Caswell Sub-basin, Prudhoe Terrace and Yampi Shelf, dominates the structural picture in WA-332-P, WA-333-P and WA-342-P. This structural orientation also dominates hydrocarbon distribution in the basin, adequately demonstrated by the strike direction of the Cornea Field structure itself. The north-westerly increase in the depth of basement across the Browse Basin is repeated in the overlying sedimentary section and is also reflected in the present day bathymetry, with water depths in the northwest sector exceeding 200 metres, shallowing to less than 100 metres on the south-eastern boundaries of WA-342-P and WA-333-P.

Stratigraphy and Major Hydrocarbon Play Elements Described By Formation

The stratigraphy of the Browse Basin is largely similar to that which appears throughout the basins and sub-basins of the Westralian Superbasin (Figure 27). The deepest part of the basin morphology can be found in the Caswell Sub-basin where a thick section of Permian, Triassic and Jurassic sediment was deposited during early syn-rift and post-rift episodes. Superimposed on the Callovian unconformity, is a thick sequence of Late Jurassic to Tertiary sediments deposited during the post rift and thermal sag phases following the separation of the Argoland microplate. On the Prudhoe Terrace to the southeast of the Caswell Sub-basin, the pre-Callovian-Permian to Middle Jurassic section was peneplained by Late Jurassic to Early Cretaceous marine trangressions and successively onlapped in a south-easterly direction by the post-Callovian deposits. The onlapping thins towards the southeast until finally the Late Cretaceous and Tertiary onlap and rest directly upon the Pre-Cambrian basement underlying the Yampi Shelf.

The following analysis examines the essential key play elements offered by each major stratigraphic formation, which in turn determines its prospectivity for the accumulation of hydrocarbons.

Kimberley Basement

The Yampi Shelf basement is an extension of the onshore Kimberley Block, which lies immediately up dip 100 kilometres or more to the southeast. The lithologies recovered in the Cornea wells recorded rock types variously described as granites, rhyolites, quartzites and even rock types of a gabbroic nature. Seismic data in the area of Cornea indicates highly rugose basement topography; a factor that sets up both the structural potential and the Cornea Field play architecture on the Yampi Shelf.

The basement structural and reservoir potential offered by the pre-Phanerozoic rock types of the Browse Basin were recognised as early as the nineteen seventies. At that time, the basement rock types had been encountered at total depth in Leveque-1, and described as gabbroic in nature. The section directly above this basement gabbroic rock type, was described as a quartzitic conglomerate and it was compared to the Proterozoic quartzites outcropping onshore in the Kimberley Block, approximately 200 kilometres to the southeast of the well location. Pre-Cambrian basement rock types were also encountered at Rob Roy-1, Londonderry-1, Gwydion-1 and in a number of the Cornea Field area wells.

The Cornea wells, Cortex-1, Macula-1, Stirrup-1 and Tear-1 were especially located to test basement closures and basement reservoir potential. The basement rock types observed in these wells was described in most cases as a rhyodacite. Some of the wells had log responses indicative of fractures but in general, where interpretations were made, the basement was considered water wet.

Cornea-2ST1 encountered oil within fractures in a cored rhyodacite between 859 and 861 metres below drill floor; the presence of oil at this depth a full 28 metres below the minimum expected free water level of 811 metres sub sea, is suggestive perhaps of the existence of a seal between the overlying Albian sands and the basement. Cornea South-1 encountered good oil shows in core samples from a section through a Permian limestone conglomerate and the underlying fractured rhyolitic basement.

At the Macula-1 location, an unweathered hydrothermally altered rhyodacite was penetrated below a weathered basement profile which extended from a depth of 988 to 1,053 metres RT. The weathered basement was described as an altered volcanic material with no attendant matrix porosity observed in thin section examination. Above the weathered basement a reworked basement talus-debris flow section extended from 943 to a depth of 988 metres RT. It was composed of argillaceous sandstone with minor interbeds of claystone and sandstone, and it was described as having 7% visual porosity. Logs however, indicated the section to be water wet and it was assigned an indeterminate “Pre-Aptian” age.

At Stirrup-1, located at the northern extremity of the Cornea Field, closure in the Proterozoic basement was identified as a reservoir objective. A 30.5 metre section was drilled into the basement and a 3.3 metre core was recovered from this interval. The lithology was defined as a hydrothermally altered rhyodacite. The material had no visible matrix porosity and no fluorescence. The core possessed abundant healed fractures oriented at 45^{o} to the core and fracture sets oriented sub-horizontally and sub-vertically throughout the bulk of the core. Log analysis using the STAR tool revealed interpreted open fracture systems over the interval 816.5 - 821 metres RT, with the fractures oriented north to south and dipping 60-80 degrees. Very weak fluorescence was observed on some of the fracture surfaces in the core.

The rhyodacitic basement and the overlying “basement wash” lithologies may therefore have reservoir potential where fracture porosity has been enhanced in the former and where intergranular porosity has been enhanced in the latter.

Permian – Hyland Bay Formation

Stratigraphically, the Permian sediments are the oldest sediments encountered by exploration drilling in the basin. The Permian has been encountered in a number of the deeper wells on the Prudhoe Terrace and the Yampi Shelf, including Leveque-1, Productus-1 located to the north of WA-342-P, Echuca Shoals-1, located 13 kilometres west of WA-332-P, Yampi-1, located 44 kilometres southwest of WA-332-P, Prudhoe-1 on the northern boundary of WA-332-P and Rob Roy-1, located within WA-333-P. The Permian section in these wells is represented by the Hyland Bay Formation. It comprises a sequence of shallow marine to paralic shales and sandstones to deeper marine shales with carbonate intervals.

The Permian section encountered within Echuca Shoals-1, is dominated by fine clastic material, but sandstones between the depths of 4,281 and 4,304 metres contained measured log porosities of 2-5% and yielded 1,175 units of mostly methane gas.

Prudhoe-1 encountered a 434 metre thick Permian section of predominantly claystones with thin sandstones, limestones and coals. Log interpretation of the sandstones yielded porosities of 9%.

Rob Roy-1 revealed a sequence of Early Permian and possibly older sediments amounting to a total 683 metres of thickness; the lower part of which had a gross sandstone content of 40% and the upper part of which had an increased sandstone content of 65%. The upper sandstones were composed of fine to medium grained occasionally coarse sandstones, considered to represent fluvial channel fill deposits and flood plain deposits. The sandy Permian deposits penetrated in Rob Roy-1 indicate reservoir potential where intermediate depths of burial maintain sandstone porosity and where the sandstones can be charged with hydrocarbons.

Triassic - Mt Goodwin, Osprey, Pollard, Challis and Nome Formations

Transgressive Triassic sands and thick open marine shales of the Mount Goodwin Formation disconformably overlie the Permian Hyland Bay Formation. A regressive pulse interrupted the open marine environment of Mount Goodwin deposition during the Mid-Triassic. The regressive phase overlies a marine limestone and is represented by a sequence of siltstones and to shales, which are equivalent in part to the Osprey and Pollard Formations of the Vulcan Sub-basin to the north.

Localised basin inversion in the Late Triassic resulted in the erosion of the earlier Triassic deposits. It post-dated the deposition of the Pollard Formation and preceded the localised deposition of a Browse Basin equivalent of the Challis Formation and its immediately overlying successor, the Nome/Malita Formation.

The equivalent of the Challis Formation has only been penetrated in the well Adele-1 within the Browse Basin, and a sand prone section equivalent to the Nome Formation has only been reported from the Yampi-1 location. Marine flooding of the Browse Basin continued through the Rhaetian and into the Sinemurian, a process which brought about the deposition of shallow marine limestones, shelfal sandstone and siltstones.

Triassic sediments have been encountered within eight wells in the Browse Basin. The Triassic was not present in the Rob Roy-1 and Prudhoe-1 wells, and is interpreted to have been eroded from or possibly never deposited over much of the Prudhoe Terrace and Yampi Shelf in permits WA-332-P, WA-333-P and WA-342-P.

The oldest of the Triassic sediments encountered in the Browse Basin occur at the Echuca Shoals-1 and Gryphaea-1 locations; here they are represented by basal transgressive sandstones. These sandstones are overlain by Early Scythian age, fully marine claystones of the Mount Goodwin Formation, containing interbeds of siltstones and occasional volcaniclastic sediments. In the overlying Anisian, regressive shallow marine sandstones, claystones and limestones of the Osprey and Pollard Formations, were distributed across the basin. These mixed lithologies are present at Yampi-1, Buccaneer-1, Discorbis-1, Copernicus-1, Brecknock-1 and at the North Scott Reef-1 location. Visual estimation of the porosities of the sandstones at the Yampi-1 location indicate low effective porosity, but at the Scott Reef-1 location, 200 kilometres west of WA-332-P, a thin Triassic dolomite and dolomitic sandstone comprises a part of the lowermost reservoir unit at the giant Scott Reef (now Torosa) gas and condensate field.

Buccaneer-1, at the northern boundary of block WA-332-P on the edge of the Heyward Graben, encountered Middle Triassic sediments below a depth of 3,325 metres RT, with a net gross ratio which was estimated at 23% and an average porosity estimated at 17%.

The Late Triassic inversion was instrumental in establishing the structural precursors of the anticlinal features that have been drilled at the Brecknock-1 and Brewster-1A locations, and Triassic sandstone reservoirs have proven hydrocarbon reservoir potential in the Browse Basin and appear to be able to maintain effective porosity to considerable depths of burial.

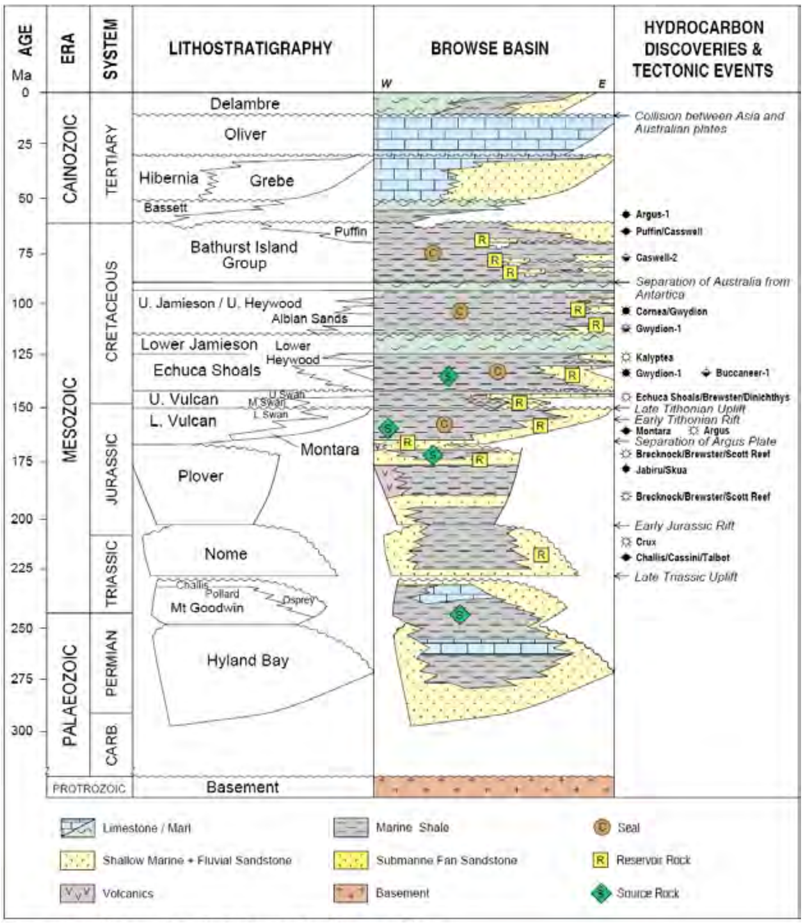

Figure 27. Generalised Stratigraphy Browse Basin

Early to Middle Jurassic - Plover Formation

An unconformity within the Early Jurassic, Sinemurian age marks the initiation of the syn-rift development of the Browse Basin. This was a period dominated by fluvio-deltaic systems of the Plover Formation that extend across the Browse basin. A second period of rifting occurs within the Plover Formation during the Early Jurassic Toarcian to Aalenian age, related to the separation of the Argoland microplate. Thick volcanic rock suites are associated with this rifting event, comprising intrusive sills and dykes and extrusive flows and ash layers. The Aalenian volcanics were followed by subsidence and a widespread marine incursion during the Bajocian that saw the deposition of shallow marine claystones which form a potential Intra-Plover formational seal.

The Upper Plover Formation is marked by the onset of a shallowing upward sedimentary cycle that grades from progradational pro-delta shales upward through sandy delta-front deposits, into interbedded coastal plain facies with local coal beds and channel sands, forming stacked sandstones sequences.

The Early to Middle Jurassic fluvio-deltaic and near shore marine sandstones of the Plover Formation formed the primary reservoir target for the initial exploration effort in the Browse Basin.

In the central Caswell Sub-basin, the Plover Formation syn-rift sequence attains an interpreted thickness of up to 1.5 kilometres. Within this very thick sequence pro-delta shale facies can be observed to locally develop significant high quality source rock potential (2% to 7% TOC), the shale units however vary widely in thickness (<1 to 25 metres). Chronostratigraphic equivalents of the pro-delta shales, within the nearshore coastal plain facies, also have significant source rock potential where they are associated with coaly intervals (1% to 15% TOC). The offshore marine facies of Early Jurassic age which generally predated the deltaic units also has developed hydrocarbon source potential with measurements indicating values of TOC >2% .

The Plover Formation is widely distributed over most of the Browse Basin and represents a primary exploration objective with demonstrated hydrocarbon reservoir effectiveness. It has been encountered in the following wells, North Scott Reef-1, Buffon-1, Scott Reef-1, Brecknock-1, Lombardina-1, Caswell-2, Brewster-1A, Dinichthys-1, Gorgonichthys-1, Ichthys-1, Ichthys Deep-1, Titanichthys-1, Adele-1 and Heywood-1. On the Prudhoe Terrace and Yampi Shelf areas the Plover Formation is generally absent, having been eroded during the Late Jurassic e.g. Prudhoe-1, but it has been locally preserved in lows such as the Rob Roy Graben e.g. Rob Roy-1, but it is present in the southern Prudhoe Terrace e.g. Yampi-1.

The Plover Formation is host to the largest gas condensate and gas accumulations yet discovered in the Browse Basin. The Scott Reef (Torosa) field has an estimated reserve of 11.5-15 Tcf of gas and 121.02 million barrels of condensate.

The discovery well encountered 24 metres of net gas sandstone within the Plover Formation and in an underlying Triassic dolomite and dolomitic sandstone. North Scott Reef-1 encountered 66.2 metres of net gas pay with similar porosities to Scott Reef-1, ranging from 11%-14%. The area of closure encompassed by the Scott Reef accumulation is 900 square kilometres and the net gross ratio calculated for North Scott Reef-1 is in excess of 50%.

Brecknock-1, located 44 kilometres to the southwest of Scott Reef, encountered another large Plover Formation gas and condensate accumulation, with an estimated 5.3 Tcf of gas and 103.3 MMbl of condensate. The adjacent Brecknock South-1 (Calliance) contains an estimated 3.9 Tcf gas and 87.99 MMbl of condensate. The Plover Formation sandstones at Brecknock-1 had log-derived porosities ranging from 11-20%, gas saturations in the order of 65-70% and sandstone net gross ratios of 70%. The Scott Reef fields comprising Scott Reef, Brecknock and Brecknock South, are now considered to have the potential to recover 20.49 Tcf of gas and 311 MMbl of condensate.

The wells on the Brewster Platform trend – Brewster-1A, Dinichthys-1, Gorgonichthys-1 Titanichthys-1 and Adele-1 all have Plover Formation reservoir targets. Brewster-1A located 44 kilometres west of WA-332-P, encountered a well developed Plover Formation in a 247 metre interval between 4,448 and 4,695 metres subsea. The interval contained 90 metres of net sandstone with porosities of less than 12%. Log interpretation of this Plover Formation sandstone section indicates in situ hydrocarbon saturation.

Heywood-1 centrally located in permit WA-341-P, located 20 kilometres north of WA-332 and WA-333-P, encountered 295 metres of Plover Formation below 4,277 metres subsea, containing sandstones, siltstones, claystones and minor coals. The loss of the drilling assembly in the borehole precluded electric logging; the net to gross ratio and porosity therefore could not be determined. However, hydrocarbon fluorescence was observed in samples down to total depth.

Late Jurassic – Lower Vulcan (Montara Formation equivalent)

Continental break-up and the creation of the Argo Abyssal Plain to the northwest of the Browse Basin margin occurred during the Callovian and Early Oxfordian, and resulted in rapid thermal subsidence. The inception of this post-rift subsidence phase coincides with the Callovian Unconformity, an erosive marine transgressive event which peneplained the top of the Plover Formation, that occurred within the *W. digitata* palynozone and is dated at 163 Ma.

The Callovian-Oxfordian is represented by sediments within the upper *W. digitata, R. aemula* to lower *W. spectabilis* palynozones which is considered to be the chronostratigraphic equivalent of the important hydrocarbon bearing reservoirs of the Montara Formation in the Vulcan Sub-basin and the Elang Formation in the Bonaparte Basin. They were deposited in a transgressive deltaic and shallow marine sequence immediately overlying the Callovian Unconformity.

The Montara Formation was probably never deposited over most of the northern Prudhoe Terrace and Yampi Shelf or was subsequently eroded during Late Jurassic, Tithonian uplift and the following Early Cretaceous, Berriasian marine transgressive peneplaination. The Buccaneer-1 on the ramp faulted margin between the Prudhoe Terrace and the Heywood Graben and the Yampi-2 well on the outer Prudhoe Terrace penetrated thin transgressive shallow marine silts equivalent in age to the Montara Formation.

The Montara Formation is considered to have good source potential for hydrocarbon generation, and is distributed downdip of the Prudhoe Terrace and Yampi Shelf.

Late Jurassic - Lower Vulcan Formation – (Lower Swan Formation)

Further rifting occurred in the Late Jurassic, Oxfordian *W. spectabilis* palynozone and subsequent post-rift thermal subsidence resulted in the creation of deep marine depocentres in the Heywood Graben and Caswell sub-basin, culminating in a maximum marine transgression in the Kimmeridgian *D. swanense* palynozone.

The Lower Vulcan Formation (Lower Swan Group) is Oxfordian to Kimmeridgian in age and is defined by the *W. spectabilis, W. clathrata* and *D. swanense* palynozones. The sequence comprises deltaic and shallow to deep marine sands and claystones. Across the central and western basins the combined Lower and Upper Vulcan Formations are rarely thicker than 200 metres. They thicken across the Leveque Platform reaching a maximum thickness in the Buffon depocentre and Heywood Graben, located within WA-341-P.

The submarine sandstones and interbedded claystones within the Lower Vulcan Formation create the possibility of discrete trapping configurations within the Vulcan Formation. Net to gross sandstone ratios for the Lower Vulcan interval approximate 20% at Brewster-1A, over 65% at Echuca Shoals-1 and 70% at Heywood-1, where a 90 metre interval containing sandstones and claystones. An electric log interpretation for sandstones within the Lower Vulcan Formation sequence at Heywood-1 indicated porosities of 10% and mud gas readings indicated some hydrocarbon saturation of the sandstones. The basal sandstones in the Lower Vulcan Formation at Brewster-1A support a probable hydrocarbon column between 4,448-4,667 metres as interpreted from electric log data. The hydrocarbon so interpreted extends into the Plover Formation and exceeds the mapped closure for the Brewster-1A closure.

Evidence of fan delta sedimentation in the hanging wall to the Heywood Graben occurs in Buccaneer-1 where 155 metres of stacked sands with thin claystones were penetrated, while further south on the outer part of the Prudhoe Terrace, the Yampi-2 well penetrated stacked shallow marine sands and claystones.

At the Heywood-1 location the Montara Formation is overlain by a thick (3,557- 4,138 metres subsea) sequence of Tithonian to Kimmeridgian deep marine claystones that form a potential seal to this play.

The Heywood Graben complex and the area of the Caswell Sub-basin adjacent to Brewster-1A are the only areas within the Browse Basin where local development of anoxic marine shales occurred, elsewhere the Lower Vulcan environment was not conducive to the formation of these rich hydrocarbon source rocks (Figure 27).

Late Jurassic to Early Cretaceous - Upper Vulcan Formation (Middle and Upper Swan Formation)

Towards the end of the Late Jurassic regional uplift occurred on the North West Shelf margin, accompanied by extensional faulting that commenced in the Early Tithonian. This tectonism is recognised in the Browse Basin by an influx of sandy submarine fans into the deep marine basin and regressive shallow marine shelf deltas along the edge of the Prudhoe Terrace.

The Upper Vulcan Formation (Middle and Upper Swan) consists of marine shales with significant interbedded sandstones. It ranges in age from Tithonian to Berriasian, thus representing a time span of approximately 10 Ma defined by the near base Tithonian unconformity and the base Cretaceous unconformity at the top of the Berriasian.

The first submarine fan sandstones recorded in the Browse Basin depocentre occurred during the Late Tithonian *D. jurassicum* palynozone. The *D. jurassicum* unit is variable in thickness; it is 190 metres thick in Echuca Shoals-1 and 363 metres thick at Heywood-1 within WA-341-P a distance of 20 kilometres north of WA-332-P. Sediments of this age are absent at Prudhoe-1 and were either not deposited on the Prudhoe Terrace or were subsequently eroded.

The end of the Late Jurassic epoch in the Browse Basin is marked by a major regression in the latest Tithonian to Berriasian, *P. iehiense* palynozone, an event which is associated with the influx of siliciclastic sediment into the basin. These sediments were widely distributed as shallow marine delta/shelf wedge sandstones in the east and thick submarine fan sandstones belonging to the Brewster Member accumulated in the basin to the west. The former sandstones comprise prograding units of vertically stacked, fine to medium grained, shore face and nearshore sandstone bars are present at Yampi-1 & 2, Buccanear-1, Echuca Shoals-1 and Prudhoe-1 locations. In the Prudhoe-1 well they rest uncomformably on deeply eroded Permian shales. These are the oldest Upper Vulcan sandstone to be deposited on the shelfward side of the Heywood Graben fault. They represent coastal onlap associated a period of overall marine transgression that persisted throughout the Early Cretaceous. Within the basinal areas of the Browse, the sedimentary processes attending the basinward facies shifts enabled the deposition of slope fan sandstones at Brewster-1A, situated 40 kilometres west of WA-332-P, at this location the sandstones host a 161.2 metre hydrocarbon column.

The final stage of the Upper Vulcan Formation sedimentary sequence occurred in the Early Valanginian with the deposition of a sandstone unit. The Berriasian and basal Valanginian units of the Upper Vulcan Formation together vary little in thickness, except in the far north and west of the central Browse Basin area where they pinchout. The thickness of the Upper Vulcan units in all of the wells on the downthrown side of the basin margin fault generally ranges in thickness between 220 and 270 metres; at the Prudhoe-1 location the thickness decreases to 173 metres.

The earliest Upper Vulcan Formation comprises Early Tithonian marine shale containing a measured organic carbon content which ranges between 2%-3% TOC. These deposits have variable thickness and are represented at Yampi-1, Caswell-2, Brewster-1A and Heywood-1; in the latter well it attains a thickness of 250 metres.

The Late Jurassic, Vulcan Formation and its chronostratigraphic equivalents in most of the North West Shelf sub-basins are considered to be the major source for liquid hydrocarbons within the Westralian Super basin petroleum systems. However, geochemical oil to source rock correlations suggest that the primary working source rock in the Browse Basin is most likely to be present within the Early and Middle Jurassic deltaic sequences and the marine Early Cretaceous Echuca Shoals Formation.

Early Cretaceous - The Echuca Shoals Formation (Lower Heywood Formation)

Following the Berriasian regression, thermal subsidence out-stripped sediment supply in the Browse Basin and a long period of basin margin transgression and drowning of the Prudhoe Terrace and Yampi Shelf ensued. Consequent sediment starvation of the basin resulted in the widespread accumulation of mud rich sediments that today form the Early Cretaceous Echuca Shoals regional seal i.e. for the pre-Cretaceous petroleum systems. The base of the Echuca Shoals Formation (Lower Heywood) is defined by the Intra Valanginian Unconformity (134 Ma) within the *E. torynum* palynozone. It is separated from the overlying Jamieson Formation (Upper Heywood Formation) by an Intra Aptian Unconformity (112 Ma) within the *O. operculata* palynozone.

Overall the Echuca Shoals Formation is transgressive in character with shallow marine sands progressively onlapping the Permian subcrop on the Prudhoe Terrace, and eventually the Yampi Shelf Basement. Following a maximum marine flood back and deposition of claystone over the Prudhoe Terrace in the Hauterivian *P. burgeri* palynozone, a regressive event occurred during the Late Hauterivian to Early Barremian. This delta/shelf regression advanced as far as the Rob Roy-1 location, before a presumed fall in sea-level at the Barremian Unconformity within the *M. australis* palynozone, resulted in a pronounced basinward shift in depositional facies, including the deposition of submarine fan sandstones in the Browse Basin depocentre and the subsequent, localised progradation of the shelf to the Prudhoe-1 location. Similar sandy, shelfal deposits occur on the landward margin of a number of the North West Shelf Basins. For example, several hundreds of kilometres to the south, on the margins of the Dampier Sub-basin, shallow marine, glauconitic *M. australis* sandstones host the Wandoo, Stag and Centaur oil and gas fields. Turbiditic and debris flow submarine fan deposits, time equivalent to the shallow marine *M. australis* sands on the Prudhoe Terrace and Yampi Shelf, have been penetrated along the eastern margin of the Browse Basin in the Brewster-1, Adele-1 and Asterias-1 locations. The Asterias-1 well penetrated an 89 metre interval of stacked, glauconitic, submarine fan sands with a net to gross of 75% and a total porosity of 22% at 3210 metres below subsea. The widespread occurrence of these submarine fan sand deposits attests to the significance of the regressive Barremian Unconformity event. In the vicinity of WA-332-P and WA-333-P, immediately seaward of the Rob Roy-1 well location, seismic interpretation supports the entrapment of a sandy debris flow submarine fan system, perched on the drowned Prudhoe Terrace. The *M. australis* submarine fan sandstones are sealed from the underlying shallow marine Valanginian *S. areolata* sands by the Early Hauterivian *P. burgeri* marine claystones, and are downlapped above by the distal fines of the subsequent *M. australis* progradational delta/shelf.

The Echuca Shoals Formation at the Gwydion-1 location, just 11 kilometres south of WA-333-P, comprises shallow marine, glauconitic *M. australis* sandstones forming reservoirs for oil. This well established the first successful demonstration of the *M. australis* sandstone play in the Browse Basin and contains a 30.5 degree API oil column between 809.5 metres and 819 metres with a gas zone above it in the overlying Albian Jamieson Formation (Upper Heywood). This interval represents the best reservoir section in the well.

In WA-342-P, approximately 100 kilometres to the northeast of Gwydion, the Echuca Shoals Formation has been identified within the Cornea area wells. Stroma-1 had a Pre-Intra Aptian Unconformity sandstone section between 628 and 657 metres, Capsule-1ST1 encountered awater bearing 35 metre thick conglomeratic sandstone, Macula-1 encountered 67.6 metres of Pre-Intra-Aptian Unconformity water bearing sandstone, Cilia-1 encountered a 33 metre thick water wet sandstone with a net to gross ratio of 70%. Retina-1, lying 90 kilometres to the northeast of the earliest Cornea wells, contains an Early Cretaceous “mound” which was the primary objective for the location of the well. The Cretaceous mound contained 27 metres of water bearing sand and claystone with a 60% net/gross ratio and some inferred porosity.

The shales in the basinward equivalent of the Echuca Shoals Formation are marine, and for the most part represent marine high stand deposits containing mixed marine and terrestrial organic matter with an average 1.9% TOC and local maxima of 4.0% TOC. The basinward Echuca Shoals Formation has been identified as a source rock, extracts of this source rock are believed to correlate, in part, with the Gwydion, Cornea and Caswell-2 oils.

The Echuca Shoals Formation has the potential to source hydrocarbons in basinward areas where it enters the oil window, while updip it has proven reservoir and seal capacity in which to accumulate any hydrocarbon charge reaching the basin margin.

Early Cretaceous – Jamieson Formation (Upper Heywood Formation)

The Jamieson Formation itself is bounded by the Intra Aptian Unconformity below and the Turonian sequence boundary above. The basin wide distribution of this sedimentary sequence is concentrated in two major depocentres, one to the southwest in the Barcoo Sub-basin (Rowley Sub-basin), and the other in the Caswell Sub-basin to the northwest.

At the shelfal locations represented by the wells Londonderry-1 and Gwydion-1, the transgressive facies sandstones in the Upper Jamieson Formation, where not occluded by claystones and greensands, have reservoir quality porosity and permeability. Gwydion-1 has three stacked glauconitic reservoirs with a gas charge below a depth of 675 metres subsea. The Cornea Oil and Gas Field was discovered by the Cornea-1, 1B and 2 wells. These wells established a 25 metre gas and an 18 metre oil column in Albian sands of the Upper Jamieson Formation. These Albian reservoirs at Cornea have been subdivided into five units with reservoir quality sandstones resident in three of the units. Correlation of the extensive well data set and the 3-D seismic coverage reveals that the Upper Jamieson Formation at the Cornea location is represented by a series of highly condensed cyclical deposits within a ravinement setting at the basin margin. The overlying and extensive Albian shale provides a cap rock seal to the underlying gas and oil accumulations.

Where it is remote from the depocentres, the basin margin distribution of the Jamieson Formation is characterised by thinning to the southeast which leads to an eventual updip pinchout of the formation onto the Yampi Shelf. The Mid Aptian to Turonian age of the Jamieson Formation encompasses a 12 Ma time span. Within this time span a further two sequence boundaries enabled basin ward shifting of coarse clastic facies including sandstones. The facies shifts are represented by thin basal sandstones in the basinward wells, which grade upward to greensands with moderate porosities. The greensands are in turn overlain by the chronostratigraphic equivalent of the Windalia Radiolarite which is widely distributed on the North West Shelf and provides a leaky seal and occasionally an oil and gas charged reservoir on the flanks of the giant Barrow Island oil field several hundred kilometres to the south in the Carnarvon Basin. The remainder of the Jamieson section is made up of siltstones and shales.

Thinning of the Jamieson Formation occurs as it progressively onlaps south-eastwards on to the Yampi Shelf. As it does so, the facies types characteristic of the underlying Echuca Shoals Formation are repeated. The vertical repetition of the Aptian sandstone, glauconitic sandstone, glauconitic fining upward claystone sequences are replicated and stacked in the overlying Albian. The Gwydion-1 location, 11 kilometres south of WA-332-P provides a well documented example of stacked Albian reservoir sequences which are gas charged and which are considered to have been deposited in a proximal shelfal setting.

At the Cornea Field location within block WA-342-P, and lying approximately 100 kilometres northeast of the Gwydion Field, the alternating sandstone, glauconitic sandstone reservoir sequence is repeated well into the Late Albian. Here, the reservoir sequence is divided into 5 sub-units, of which the “B”, “C” and “D” units are considered to contain reservoir quality sandstones. The remaining two units are considered to be waste zone siltstone and shale respectively. All of the

Cornea reservoir and non-reservoir units are overlain by the Albian shale which is considered to be an imperfect seal in the area, allowing vertical leaking of hydrocarbons at some locations.

The youngest of the remaining Cretaceous sequences is represented by the Bathurst Island Group. It lies above the Jamieson Formation and extends to the overlying Base Tertiary horizon. The Bathurst Island Group contains the Browse Basin equivalents of the Woolaston, Gibson, Fenelon and Puffin Formations, and a number of important erosional events occur within this succession. Of these erosional events there are two significant unconformities that affect the distribution of Late Cretaceous reservoir potential within the basin. The youngest of these events, the Early Campanian unconformity is marked in the well bore data by the introduction of fluvio-deltaic sandstones into the updip areas of the basin. The Early Campanian unconformity resulted from a major sea level fall of sufficient magnitude to enable the deposition of lowstand submarine fans well beyond the Yampi-1 location. The Campanian sea level fall sandstones were projected out into the Caswell Sub-basin to the Caswell-2 location, 120 kilometres west of WA-332-P and also out to the Kalyptea-1/ST 1 location, 50 kilometres northwest of WA-342-P.

Seismic and Well Database

There are no well penetrations in WA-332-P, although Buccaneer-1 and Prudhoe-1 both lie immediately across the northern boundary of the permit (Figure 28). Echuca Shoals-1 is located 12.5 kilometres to the northwest, and Gwydion-1 and Caspar-1A, are located 11.5 and 14 kilometres respectively to the south. The data for all of these wells is entirely openfile.

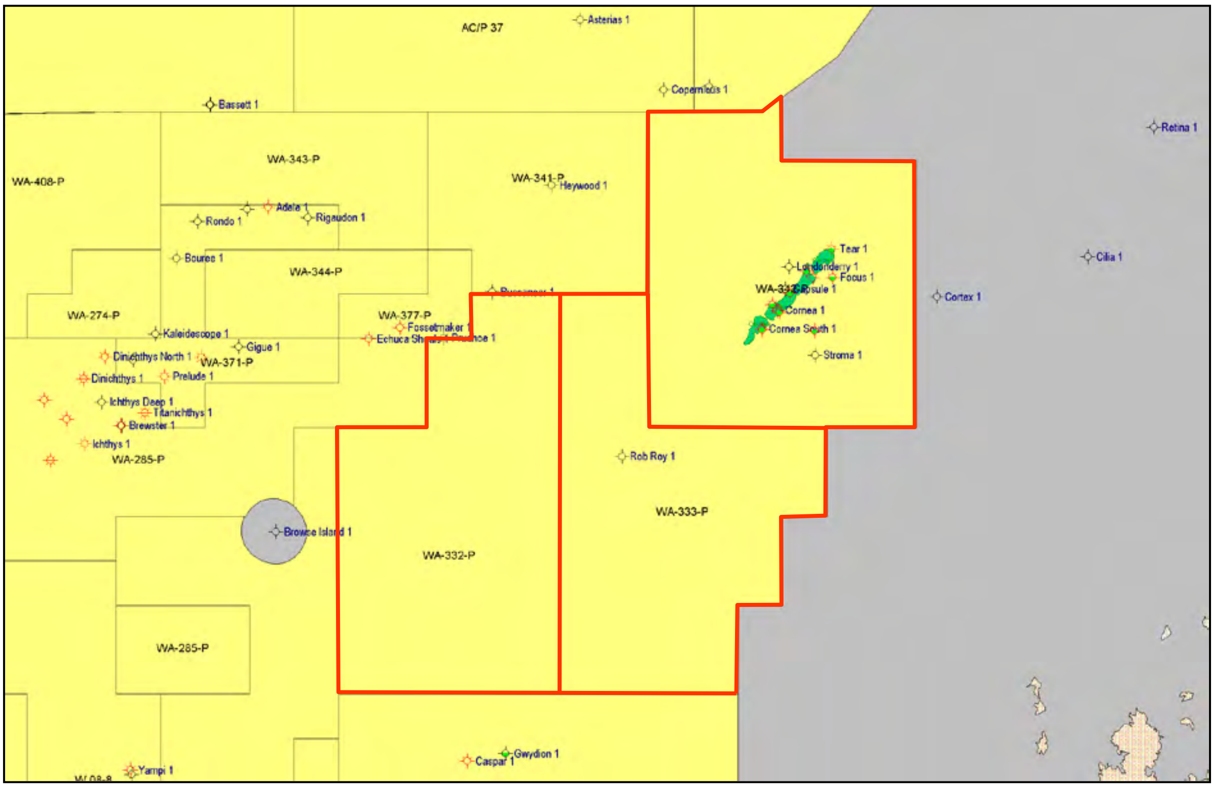

Figure 28. Well Database

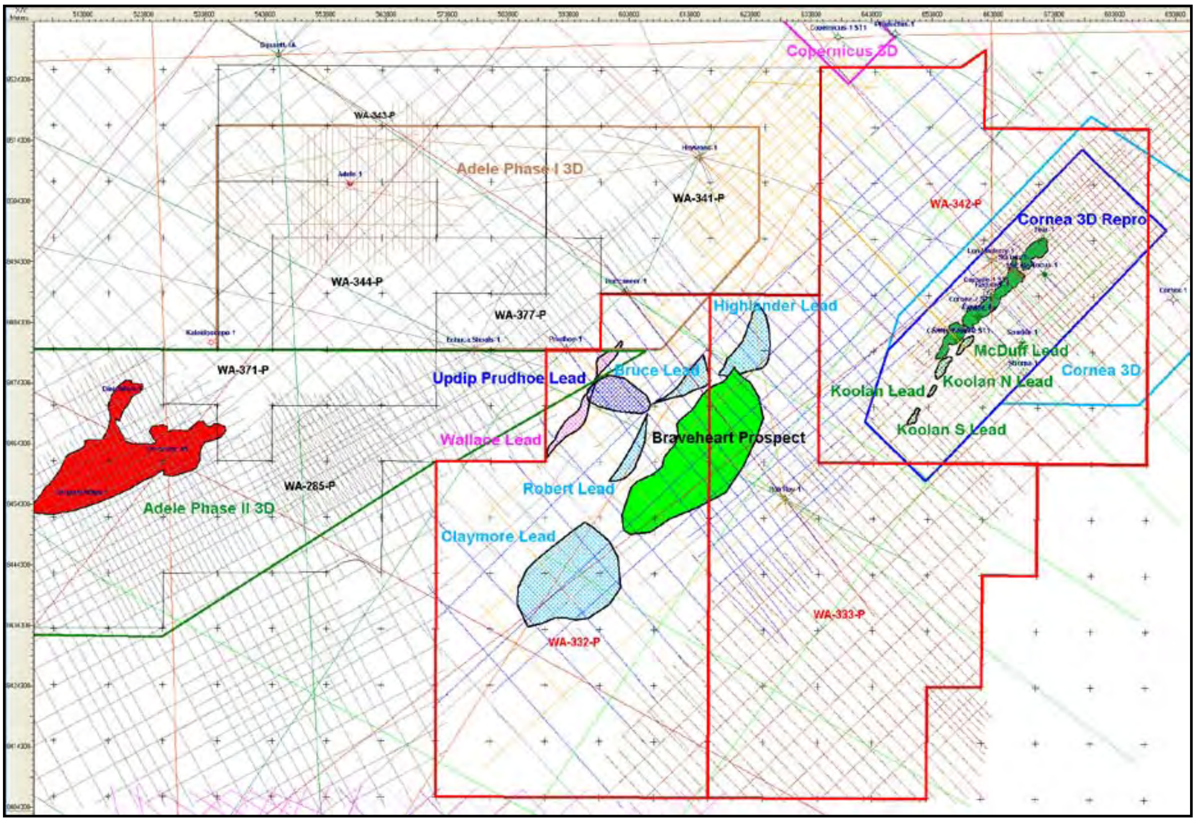

Figure 29. Seismic Database

There is one well penetration, Rob Roy-1, in WA-333-P, and there are 13 well penetrations in WA-342-P, mostly associated with the Cornea Field trend or on adjacent, similar features. The data for all these wells is also entirely openfile.

The central and southern part of WA-332-P and the northern part of WA-333-P is covered by broad spaced 2D seismic that was acquired in the late 1960's and early 1970's. These seismic data have been recently reprocessed with a substantial improvement in resolution. The northern most parts of WA-332-P and WA-333-P are covered by closer spaced 2D seismic surveys acquired in the mid to late 1980's. These have also been reprocessed and phase matched with the 1960/70's seismic. (Figure 29).

In 1992, Mobil Exploration and Production Australia acquired the 198.8 square kilometre Copernicus 3D in AC/P3, a small part of which is now located in WA-342-P (Figure 29).

In 1995 and 1996 Shell acquired high quality (1x2 and 2x4 kilometre) 2D seismic surveys that covers the south-eastern part of WA-332-P, most of southern and central WA-333-P and eastern WA-342-P. They subsequently acquired 2,092 square kilometres of 3D seismic over the Cornea Field trend in 1997/8, and that now covers most of the eastern part of WA-342-P. The western part of WA-342-P is sparsely covered by 2D seismic, acquired in the 1960/70's and mid to late 1980's. (Figure 29). These seismic surveys have recently been reprocessed with a substantial improvement in resolution (Figure 29).

In 2001 Western Geco shot the Adele Trend speculative 3D seismic survey in the eastern Caswell Sub-basin. This 3D seismic survey extends into the northwestern part of WA-332-P permit and extends into the adjacent WA-341-P permit (Figure 29).

In 2005 and 2006 Hawkstone Oil acquired the Braveheart 2D seismic survey over the seismically sparsely covered parts of WA-332-P, WA-333-P and WA-342-P, and including well tie lines to Prudhoe-1, Buccaneer-1, Rob Roy-1 and the Cornea Field wells for the purpose of calibrating the petrophysics of the geology in these wells with the new seismic data.

In 2007 amplitude versus offset (AVO) analysis was applied to the newly acquired Braveheart 2D seismic to assist in the identification of hydrocarbon traps within the Late Jurassic and Early Cretaceous plays.

In 2007 the prospective, western part of the Cornea 3D acquired by Shell in 1997/8 was reprocessed to better resolve the field and surrounding leads, as de-multiple processing was not applied to the original 3D seismic volume.

Prudhoe Terrace and Yampi Shelf Play Types and Prospectivity in WA-332-P, WA-333-P and WA-342-P

The Latest Jurassic to Early Cretaceous play types that have been identified in the permits WA-332-P, WA-333-P and WA-342-P fall into a distinctive group; the Prudhoe Terrace/Yampi Shelf group based on structural style, reservoir development and reservoir age (Figure 30). They comprises a series of marine transgressions and regressions that progressively onlap the Prudhoe Terrace towards the east, and eventually the crystalline Yampi Shelf basement itself. These transgressive and regressive units naturally fall into distinctive formations - as the Upper Vulcan (Middle Swan) and the Echuca Shoals (Lower Heywood) formations. Each regression deposited onlapping shallow marine sandstones that were sealing by shales of a subsequent marine transgression. The Berriasian contains two such shallow marine onlap plays. The oldest, comprising *P. iehiense* and *K. wisemaniae* sandstones, is located on the outer margin of the Prudhoe Terrace and fed the youngest of the submarine fan complexes in the Heywood Graben. The underlying shales of the Early Permian provide a base seal for this play.

Six separate play types have been recognised and these are summarised below:

Shallow marine Tithonian to Berriasian sandstone Onlap Play

The Prudhoe-1 well penetrated shallow marine sandstones of interpreted latest Tithonian to Berriasian age that are overlain by the Berriasian *K. wisemaniae* marine transgressive claystones. On seismic evidence, these sandstones pinchout updip of the Prudhoe-1 well location, thereby creating a potential trap, as they onlap the Permian shale subcrop and are overlain by the *K. wisemaniae* marine transgressive claystones.

One lead has been identified in this play in the northern part of permit WA333-P (Figure 31):

- Wallace Lead

Berriasian shallow marine sandstone - Onlap Play

The second, younger Berriasian onlap play comprising *C. delicata* sandstones, occurs in the central part of the Prudhoe Terrace. The top of this play may have been truncated by the Intra Valanginian Unconformity, as there is apparent missing section in the Prudhoe-1 well between these sandstones and the overlying transgressive marine shales. Base seal for this play is provided by the *K. wisemaniae* marine transgressive claystones and also the underlying Early Permian shales.

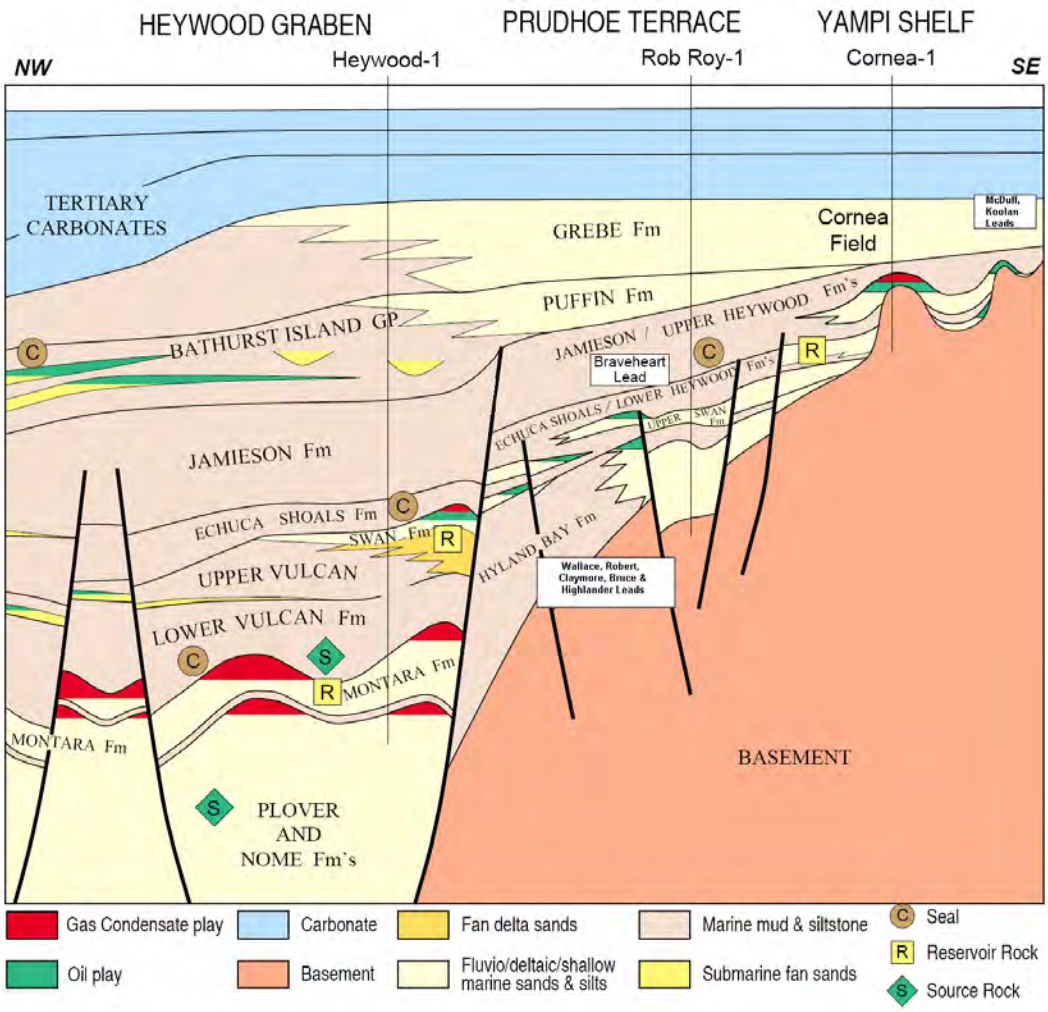

Figure 30. Prudhoe Terrace and Yampi Shelf cross-section and play types.

Three leads have been identified in the second Berriasian onlap play in the northern parts of permits WA-3323-P and WA-333-P (Figure 31):

- Robert Lead
- Bruce Lead
- Highlander Lead
- Claymore Lead

Barremian submarine fan sandstone -Onlap Play

Following the Early Cretaceous Hauterivian *P. burgeri* marine transgression and the establishment of deep marine conditions on the Prudhoe Terrace, a regressive event during the Hauterivian to Barremian introduced shallow marine *M. australis* sandstones onto the south-eastern margin of the Prudhoe Terrace as a prograding delta/shelf wedge. A fall in sea-level during the Barremian resulted in the deposition of a sandy submarine fan at the base of the delta slope on the drowned Prudhoe Terrace. Top seal is provided by shales that were deposited during the subsequent progradation of the upper *M. australis* delta/shelf. The Barremian *M. australis* sandstones form the oil reservoir in the Gwydion Field to the south of permit WA332-P (Figure 31).

One Barremian Prospect has been identified that straddles permits WA-332-P and WA-333-P (Figure 31):

- Braveheart Prospect

Barremian submarine fan sandstone - Stratigraphic Play

Progradation of the Barremian upper *M. australis* delta/shelf extended basinwards to just beyond the Prudhoe-1 well which penetrated porous shallow marine sandstones. These are overlain by the marine claystones of the latest Barremian *A. cinctum* transgression.

One Barremian Lead has been identified in permit WA-332-P (Figure 31):

- Updip Prudhoe Lead

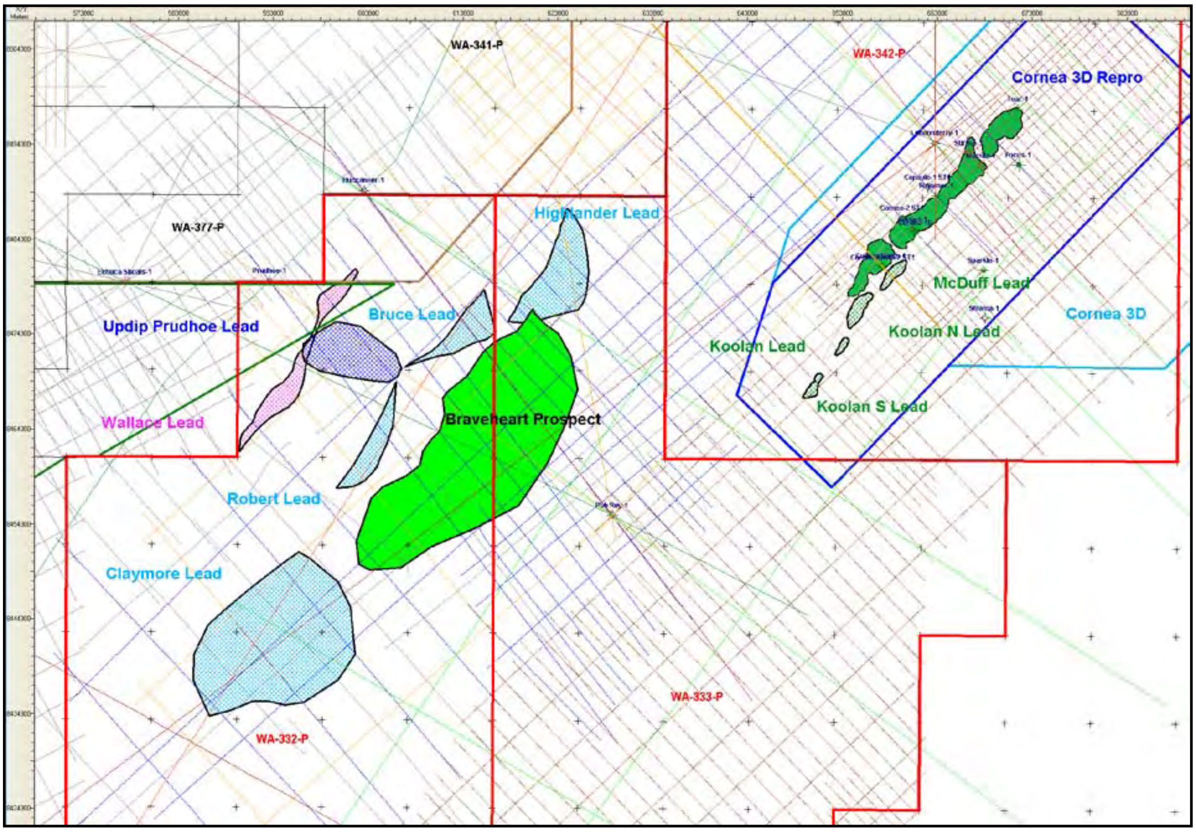

Figure 31. Leads map Northern Browse Basin

Aptian shallow marine sandstone - Drape Play

A regional unconformity in the Aptian reintroduced shallow marine sediments to the Yampi Shelf and the south-eastern Prudhoe Terrace as the Upper Jamieson (Upper Heywood) Formation. Two main regressions are recognised, one in the

Late Aptian - *D. davidii* sandstones and the second during the Early Albian - *M. tetracantha* sandstones. The Late Aptian and Early Albian sandstones are sealed by the Early Albian *C. denticulata* marine claystones and are a target in drape leads in permit WA-342-P.

A number of Aptian to Albian sandstones drape leads have been identified on the reprocessed Cornea 3D seismic in permit WA-342-P (Figure 31). The Four largest are:

- Koolan South Lead
- Koolan Lead
- Koolan North Lead
- Mc Duff Lead

Albian marine sandstone – Drape Play

The Albian P. ludbrookiae sandstones are the main oil and gas reservoir in the Cornea Field. They have high porosity but variable permeability, but are expected to become more permeable towards the sediment source in the east.

One lead represents this play type (Figure 31):

- McDuff Lead

Description of Prudhoe Terrace & Yampi Shelf Prospect and Leads

The individual Prospects and Leads are described as follows:

Wallace Lead

The Wallace Lead lies 6 kilometres updip of the Prudhoe-1 well on the outer edge of the Prudhoe Terrace in permit WA-332-P (Figure 31). The trapping mechanism comprises a stratigraphic pinchout immediately above the Base Cretaceous Unconformity. Base seal is provided by the Early Permian Shales that subcrop the Base Cretaceous Unconformity and top and lateral seal by Berriasian marine transgressive shales (Figure 32). The lead has a mapped closure of 28 square kilometres with the crest at 2,540 metres subsea and the lowest closing contour is at 2,635 metres subsea. The reservoir target is shallow marine Berriasian sandstones of the Upper Vulcan (Upper Swan) Formation that have been penetrated in Prudhoe-1 between 2,800 and 2,830 metres where they comprised predominantly medium grained sandstones with up to 17% porosity.

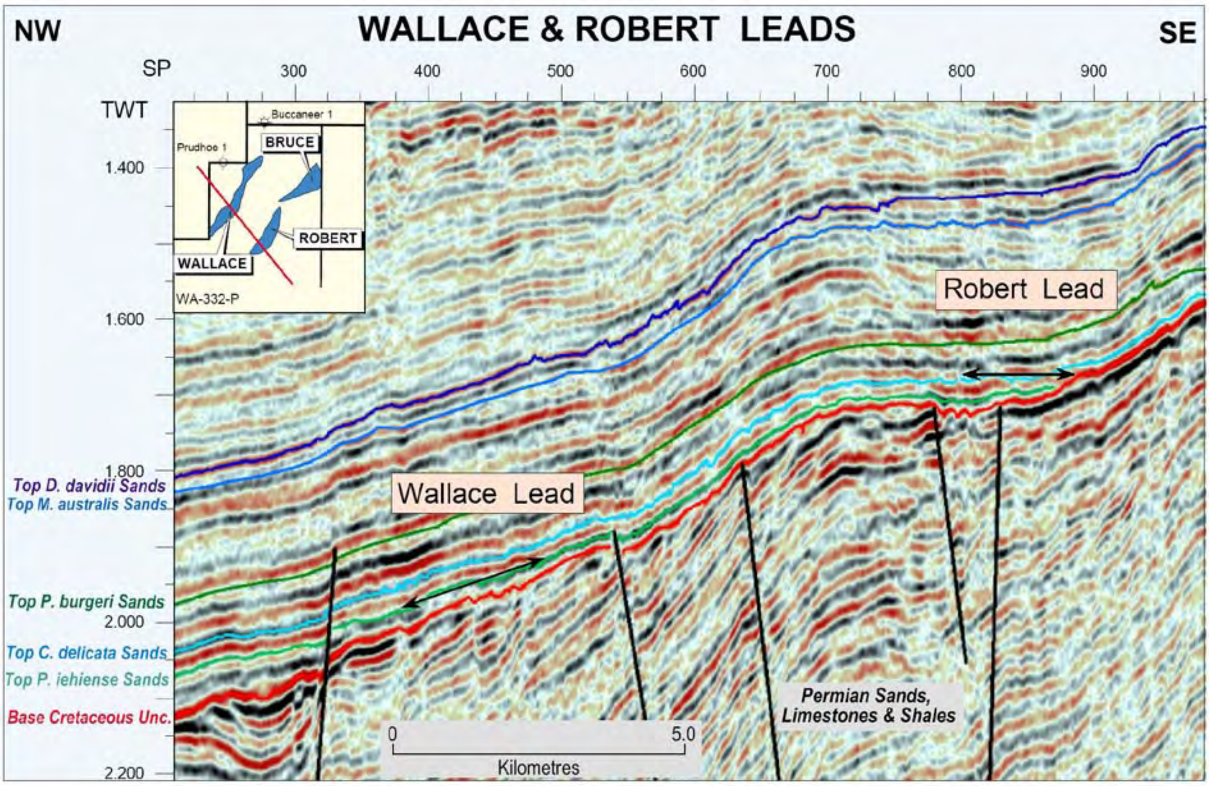

Figure 32. Wallace & Robert Leads, Seismic Line M200-22

Claymore, Robert, Bruce and Highlander Leads

The Claymore, Robert and Bruce Leads are located on the Prudhoe Terrace between the Heywood and Rob Roy grabens. They lie 17 kilometres updip of the Prudhoe-1 and Buccaneer-1 wells in permit WA-332-P (Figure 31). The Highlander Lead is situated within the northern end of the Rob Roy Graben, 20 kilometres updip of the Buccaneer-1 well in permit WA-333-P (Figure 31). The trapping mechanism for all three leads comprises a stratigraphic pinchout of shallow marine Berriasian, *C. delicata* sandstones of the Upper Vulcan (Upper Swan) Formation. The reservoir immediately overlies the Base Cretaceous Unconformity and subcrops the Intra Valanginian Unconformity. Base seal is provided by the subcropping Early Permian Shales and top and lateral seal by Valanginian marine transgressive shales (Figure 32). Prudhoe-1 penetrated this play downdip of the pinchout between 2,752 and 2,778 metres and reported medium grained sandstones with up to 17% porosity. The Robert and Bruce Leads have mapped closure of 18 and 21 square kilometres respectively, with the crest of the pinchouts at about 2,170 metres subsea and the lowest closing contour at 2,255 metres subsea. The Highlander Lead is larger, with a mapped closure of 49 square kilometres. The main risk associated with these leads is definition and integrity of the pinchout. The presence of oil updip in the Cornea and Gwydion discoveries indicates that hydrocarbons have migrated across the Prudhoe Terrace from a Heywood Graben source.

Braveheart Prospect

The Braveheart Prospect is located above the western footwall of the Rob Roy Graben (Figure 31). The primary reservoir target is Barremian *M. australis* submarine fan sandstones of the Echuca Shoals (Lower Heywood) Formation. The Braveheart Prospect is defined on the Braveheart 2D seismic acquired in 2005/6 (Figure 33). It comprises a prominent amplitude anomaly that was shown to possess an amplitude versus offset (AVO) anomaly (Figure 36), suggestive of the presence of hydrocarbons. Similar AVO anomalies occur on the Braveheart 2D over the Cornea Field and in a reprocessed vintage 2D seismic line through the Gwydion-1 oil and gas pools.

The Braveheart Prospect is shared between permits WA-332-P and WA-333-P (Figure 31).

The seismic line shown below – B05-25 (Figure 33) illustrates the strongly northwest structural dip that has been imparted to the Prudhoe Terrace by the collapse of the Browse Basin margin during the Cretaceous and the Tertiary.

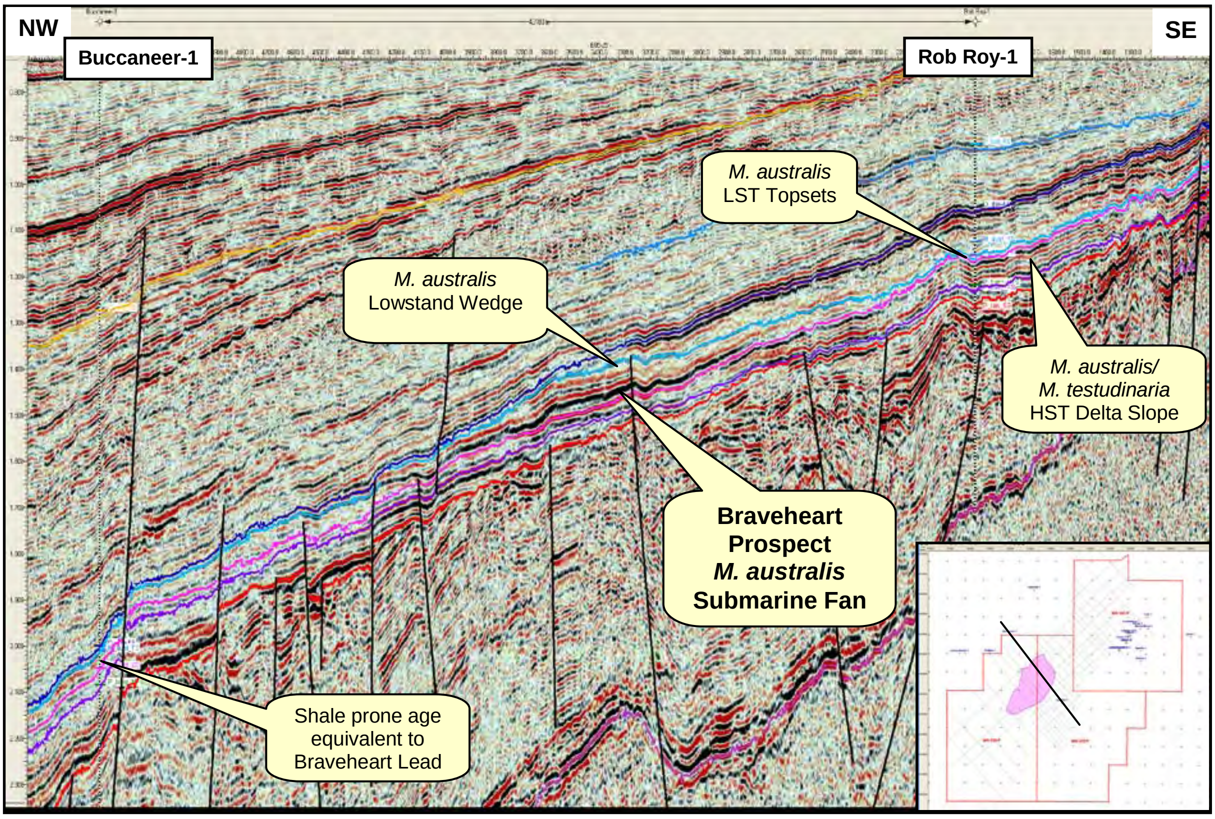

Figure 33. Illustrating the location of the Braveheart Prospect on seismic line B05-25 and between the Buccaneer-1 and the Rob Roy-1 well locations.

The Lower Heywood Formation on the Prudhoe Terrace is dominated by sediments deposited within the *M. australis* palynozone, this zonation has been used to correlate the well data, from which the sequence stratigraphic framework displayed in Figure 34 was derived.

The sequence stratigraphic framework was used to aid the interpretation of the seismic data on the Prudhoe Terrace, by removing the pervasive regional structural dip (Fig.34) the interpreted original depositional relationships can be unraveled and the form of the interpreted *M. australis* submarine fan revealed.

The time equivalent sediments revealed in other exploration wells in the Browse Basin (Fig.35) reveal a propensity for inclusion of sandstones in the *M. australis* sequences, which indicates that large amounts of potential reservoir material was being stripped from the cratonic basement to the east and being poured into the Browse Basin during the Barremian.

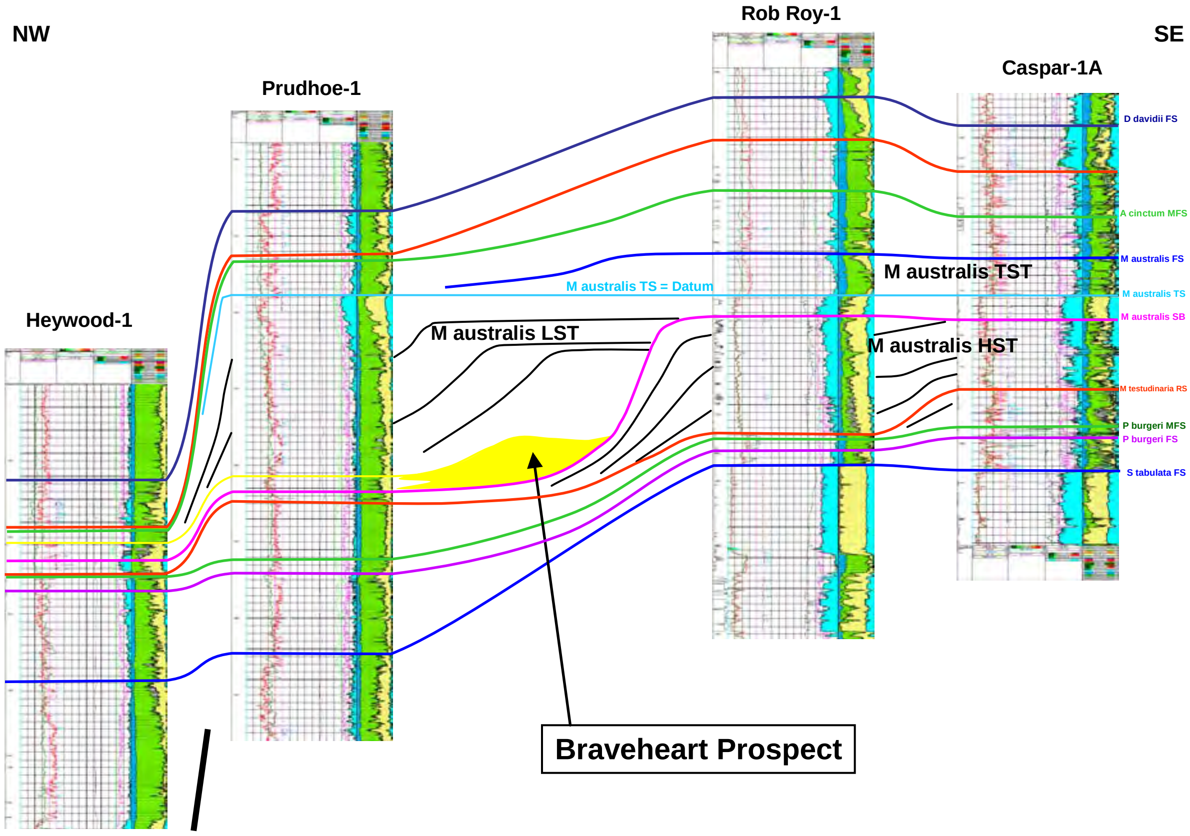

Figure 34. A sequence stratigraphic framework for the Braveheart Prospect - M. australis submarine fan within the existing well settings.

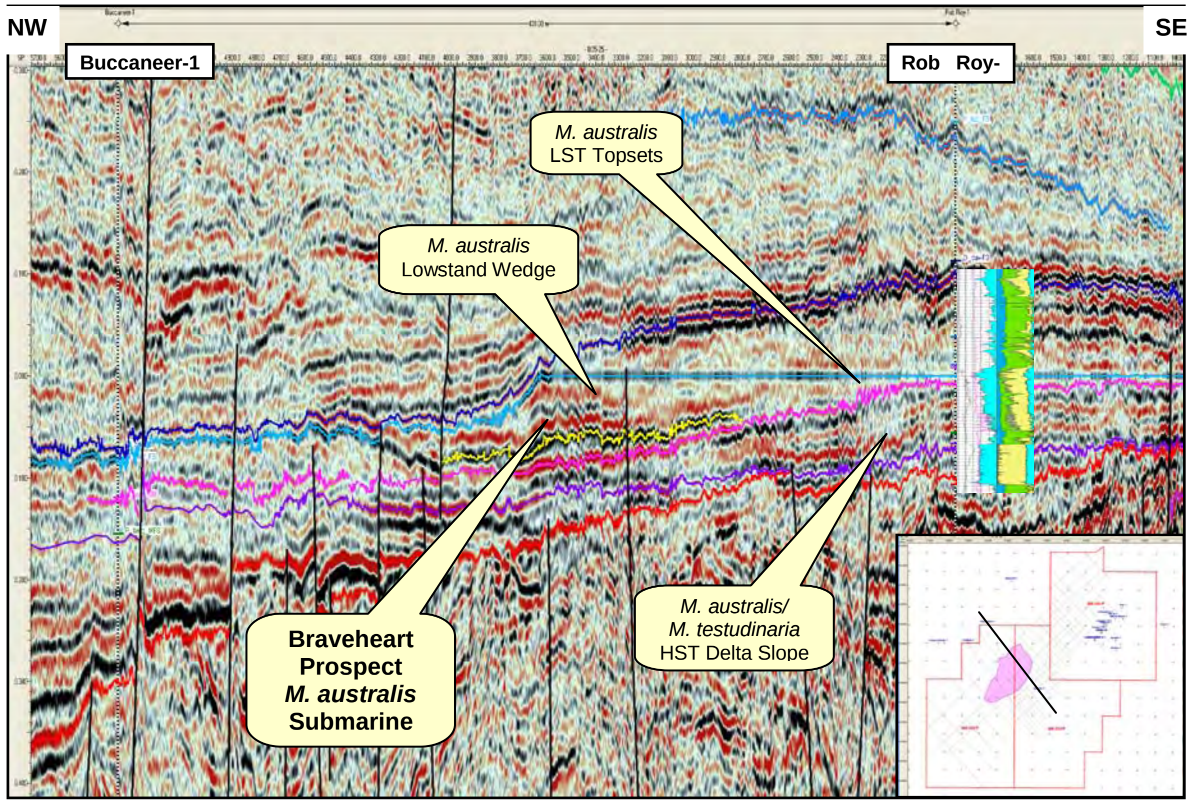

Figure 35. A re-presentation of seismic line B05-25 illustrating the Braveheart – M. australis submarine fan prospect, with the M.

australis topset beds (blue line horizon) flattened to their interpreted original depositional orientation to match the sequence stratigraphic (blue line horizon) in the framework diagram above.

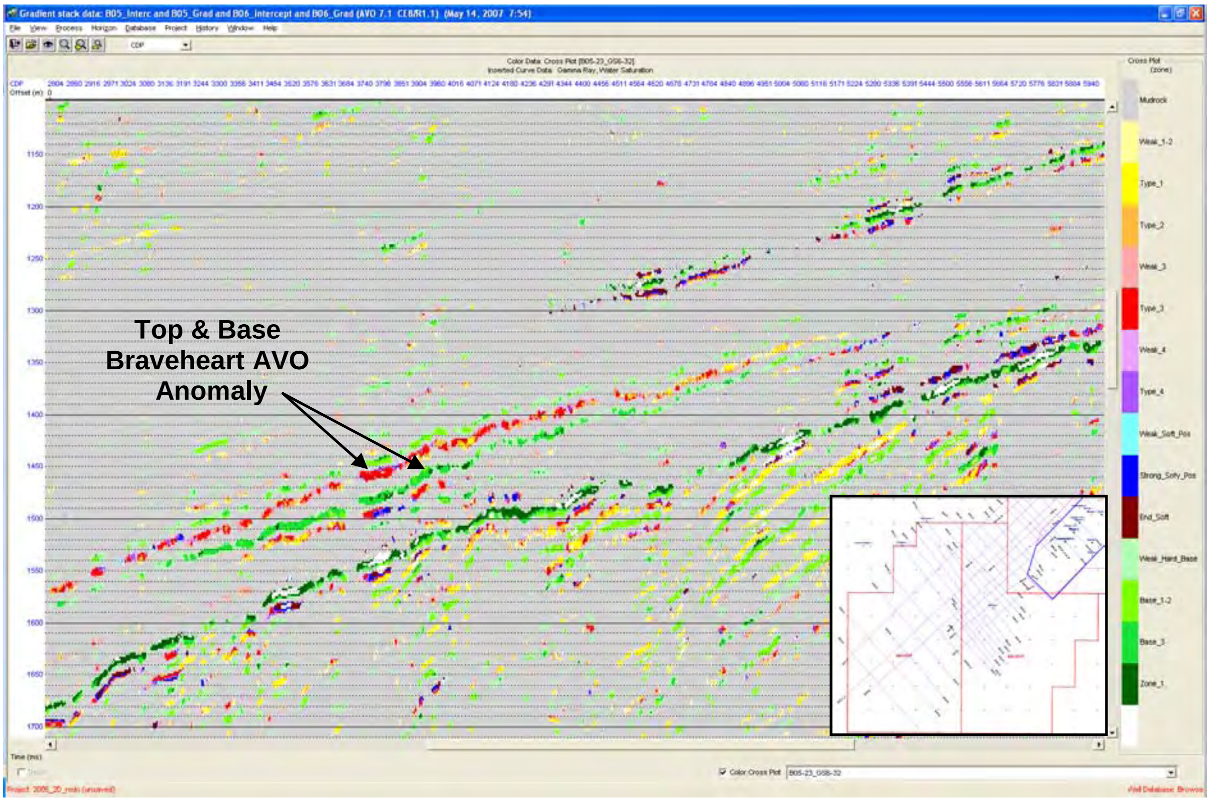

Figure 36. Illustrating the Braveheart - M. australis AVO Anomaly, as illustrated on seismic line B05-23.

The interpreted submarine fan is identified on the seismic data by the higher amplitude response (Figure. 37) recorded by the seismic data compared with the equivalent sequence elsewhere on the Prudhoe Terrace. The overall form of the amplitude anomaly corresponds to what might be expected of a submarine fan deposit lying at the base of an interpreted palaeoshelf edge. The strength of this anomaly and its approximate conformance with the time map (below – Figure. 37) suggests that the anomaly is unlikely to be an artifact.

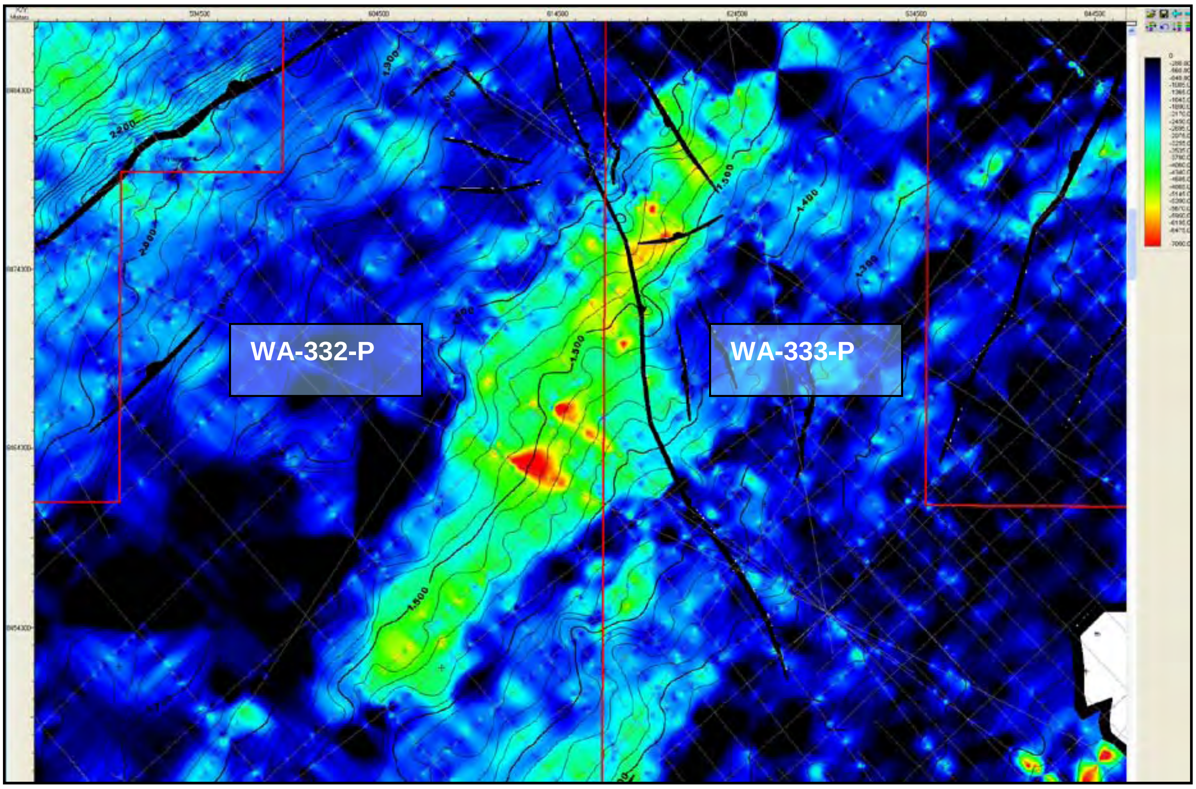

Figure 37. Illustrating the Braveheart - M. australis submarine fan deposit as it is imaged in the Prudhoe Terrace seismic data set. The higher amplitude response illustrated in this data set is shown in green on the figure above. It is located forward (basinward) of the interpreted M. australis shelf edge.

There is a pronounced base and top amplitude anomaly associated with the Braveheart Submarine fan geobody that extends to an interpreted areal distribution of between 200 and 400 square kilometres respectively, while the AVO anomaly extends over an area of 300 square kilometres. The downdip limit of the seismic amplitude anomaly i.e. the northwestern edge of the anomaly, representing the top of the interpreted submarine fan sandstone is shifted basinwards i.e. northwestwards, with respect to the base amplitude anomaly. This shift can be interpreted as seismic imaging of a hydrocarbon water contact. Geophysical modelling of the AVO anomaly suggests that it is considered likely to indicate the presence of hydrocarbons (oil, gas or non commercial gas in solution) than sandstone thickness or porosity. Thick, porous Valanginian *S. areolata* and Barremian *M. australis* sandstones penetrated by the Rob Roy-1 well immediately to the southeast did not possess an AVO anomaly.

At the Gwydion-1 location to the south, the Barremian *M. australis* sandstone is the principal oil reservoir in a sub 2 kilometre closure with a 9.5 metre oil column of 30.5 degree API and an oil in place calculated to be 11.0 MMBL.

Updip Prudhoe Stratigraphic Lead

A 45 square kilometre AVO anomaly has been identified on the new Braveheart 2D seismic, updip of the Prudhoe-1 well location (Figure 31). The anomaly is interpreted to occur in the same water wet Barremian upper *M. australis* sandstones penetrated in the Prudhoe-1 well which did not possess and AVO anomaly. The upper *M. australis* sandstones occur near the outer margin of the prograding delta/shelf extended and are overlain and sealed by the marine claystones of the latest Barremian *A. cinctum* transgression.

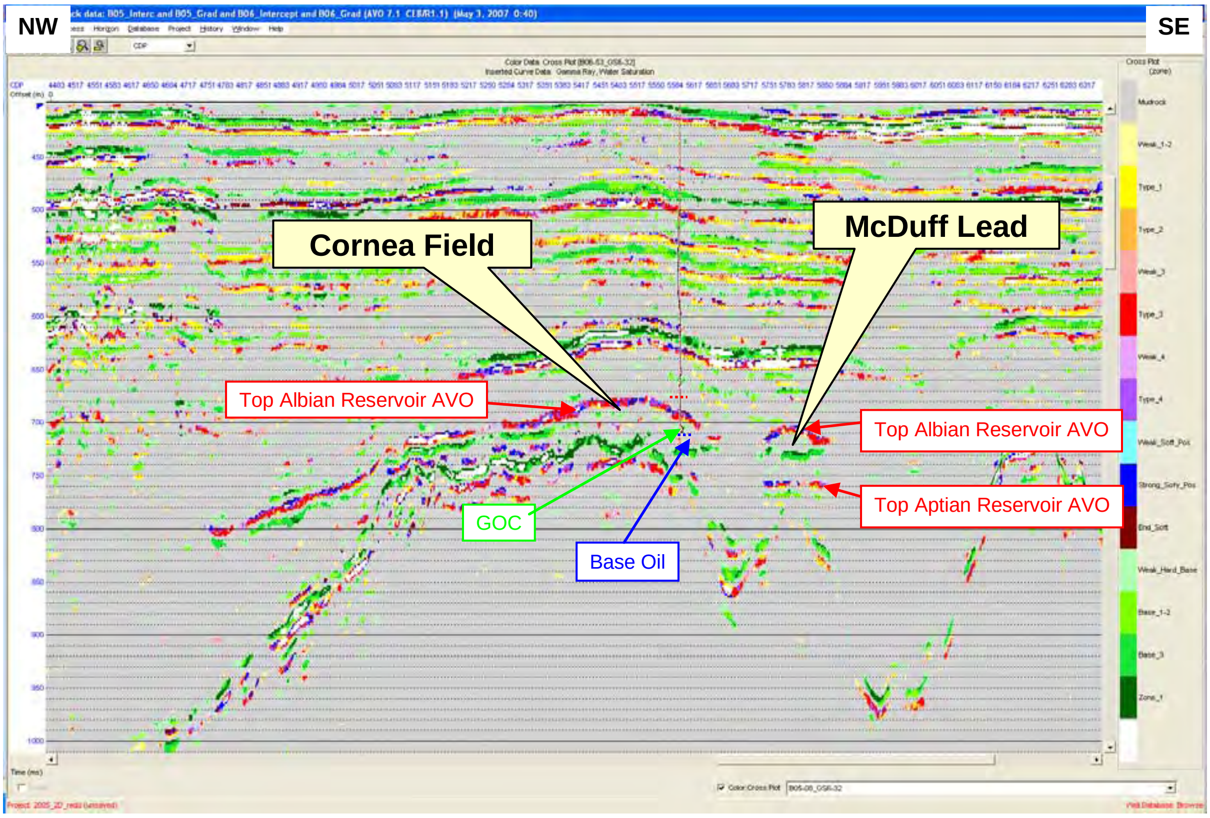

Figure 38. McDuff Lead, Seismic Line B06-49 showing stacked Albian and Aptian AVO anomalies.

McDuff, Koolan North, Koolan, Koolan South Leads

In WA-342-P the Cornea Field was discovered by the early exploration wells Cornea-1, 1B and 2. They established the presence of a minimum 25 metres gas column and a minimum 18 metres oil column in the Albian *P. ludbrookiae* sandstones of the Jamieson Formation. The field is a large drape feature enclosing Albian sandstones. It accumulated 18 to 22 degree API oil derived from Early Cretaceous, Echuca Shoals Formation and possibly Late Jurassic source rocks in the Heywood Graben, located over 60 kilometres to the west. The field is split into three main structural components – Cornea South, with gas and oil, Cornea Central with gas and oil and Cornea North with gas and no underlying oil presence.

Similar Albian sandstone drape features have been recognised in the McDuff, Koolan North, Koolan and Koolan South leads on reprocessed Cornea 3D seismic, in a basement high trend parallel with the Cornea Field (Figure 31). However, these drape leads occur over lower basement topography that in the Cornea structure and as such also have the better quality Aptian to early Albian sandstone reservoirs draped over basement with the intervening seal interpreted to be intact. This potentially allows stacked hydrocarbon pools, as indicated by the AVO anomaly in the McDuff Lead (Figure 38) which was not observed in the Cornea Field.

Exploration and Expenditure - Programmes

In WA-332-P the company has committed to the acquisition of available open file reports, seismic and well data, the integration and evaluation of this data. It has also committed to acquire 1,200 kilometres of newly reprocessed proprietary 2-D seismic data and a further acquisition and processing of 500 kilometres of new 2-D seismic data in the first three year permit term. Should the company so decide it can elect to enter a second three year term in which it has indicated it will drill one well and shoot and process 400 kilometres of new seismic data.

In the first three year permit term of the WA-333-P permit, the company has committed to acquire available open file reports, existing seismic and well data and to synthesize and integrate this information with mapping. The company will also acquire not less than 1,200 kilometres of newly reprocessed proprietary 2-D seismic data, it will also acquire and process 500 line kilometres of new 2-D seismic data. Should the company so decide, it can elect to enter a second three year term in which it has indicated that it will drill one well and shoot and process 400 kilometres of new seismic data.

In the first three year term of the WA-342-P permit the company has committed to the collection and synthesis of available data including seismic and well data. It has also committed to acquire not less than 800 kilometres of proprietary newly reprocessed 2-D seismic data and interpret areas of interest. It will acquire and process 500 line kilometres of new 2-D seismic data to infill the seismic grid over the best leads developed. The company has committed to the interpretation of this data set so that, if it should choose to do so, it can enter the second three year permit term in which it has indicated it will drill one exploration well.

The Company has acquired approximately 2,000 kilometres of new 2D data in WA-332-P, WA-333-P and WA-342-P and has reprocessed approximately 1,000 kilometres of 3D data in WA-342-P. The Company plans to drill the Braveheart 1 well in WA-333-P in 2009.

In the opinion of the author, the company has developed and committed to a satisfactory and clearly defined work programme, which is reasonable having regard to the stated objectives of the company.

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SECTION 5

THE BRIGADIER RANKIN TREND PERMIT – WA-359-P

Introduction

The Carnarvon Basin is one of a number of sedimentary basins and sub-basins which together lie within the extensive and world class, North West Shelf Hydrocarbon Province of Australia.

The North West Shelf Province contains an estimated 2.6 billion barrels of oil, 2.6 billion barrels of condensate and 152 trillion cubic feet of gas within 233 hydrocarbon fields, 67 of which are developed and producing. The WA-359-P permit boundary lies just 20 kilometres due north of the presently producing North Rankin Field complex. A field which was first discovered in 1971 and has along with other NWS Venture fields a current yearly capacity of 11.9 million tonnes of LNG (GSWA); most of which is exported overseas in 100's of pressurised and refrigerated ship cargoes. The WA-359-P permit as represented in Figure 39, occupies an area of approximately 1,210 square kilometres and comprises 15 graticular blocks.

Exploration History of the Northern Carnarvon, Brigadier-Rankin Platform

To date one well, Brigadier-1, has been drilled within the area which is now encompassed by the permit boundaries of WA-359-P. Far beyond the confines of WA-359-P, exploration in the greater Carnarvon Basin area began in 1954, with the field mapping of Barrow Island. Almost exactly a decade later the Barrow Island anticline was tested at the Barrow Island-1 location. Nearly twenty years later and by the end of 1983, 190 million barrels had been produced from Barrow Island. Presently the cumulative production of Barrow Island has reached a third of a billion barrels of oil.

Offshore drilling began in the Carnarvon Basin in 1968 with the then non-commercial oil discovery at Legendre-1. In 1971, the first major offshore discovery was made with North Rankin-1 on the Rankin Trend, located immediately south of WA-359-P. This discovery was followed shortly thereafter by others at Angel, Goodwyn and West Tryal Rocks. The North Rankin Field was brought into production in 1984, becoming the first of the major North West Shelf gas fields to reach this stage of development.

Presently developed fields and those with potential for short term development along the Rankin Trend possess P 90 volumes for oil of 100 million barrels, condensate of 290 million barrels and gas volumes of 15 Tcf.

More recently, successful oil exploration has occurred at the Mutineer-Exeter Field approximately 10 kilometres southeast of WA-359-P. The appraisal and development of the Mutineer-Exeter Field complex enabled first production to be announced on 29th March 2005. The $440 million project produced 100,000 barrels of oil per day during the start-up phase from four horizontal development wells, but current production is at approximately 20,000 barrels per day. The original indicated reserves for the fields ranged from 55 million barrels to 169 million barrels of oil (re-rated to 61 million barrels of proved and probable oil). Production from the field is handled by an FPSO vessel moored between the two fields, located approximately 10 kilometres apart.

Within the present WA-359-P permit boundary, an early 1978 test - Brigadier-1, was located on a large north-easterly trending horst structure. The well reached a total depth of 4,292 metres in Upper Triassic sediments which contained minor coals. Below 4,125 metres the Upper Triassic sediments contained some sample fluorescence, but no significant hydrocarbons were discovered in the well.

A distance of 48 kilometres southeast of the Brigadier location, a 1972 oil discovery at Eaglehawk-1 encountered 13.9 metres of net oil sandstone which flowed at a rate of 1,645 barrels per day of 29 degree API oil. A distance of 55 kilometres to the southeast of Brigadier-1, the Lambert-1 discovery was made in 1974. A step-out well, Lambert-2, was drilled in 1996. The well encountered a 37 metre oil column in Late Jurassic sandstones and a further 133 metre gas column in Early Jurassic sandstones. Lambert-2, subsequently renamed the Hermes Field, went on production in 1997, with early estimates of oil reserves assessed as 12 million barrels of oil and with the possibility of further proved and probably reserves of 24 million barrels of oil (recently re-rated to 35.47 million barrels by GSWA). A little less than one kilometre to the west of WA-359-P, a 180 square kilometre structure with some 200 metres of vertical closure was drilled at the Banambu-1 location in 1998. Banambu-1 was the first of a four well commitment in the adjoining WA-269-P permit. The well encountered the Triassic reservoir objectives, but no shows were encountered and the petrophysical evaluation indicated all reservoir sandstones to have been water wet. Erosion beneath the Middle Jurassic Callovian unconformity had also removed the prospective Legendre Formation sandstones. The well was plugged and abandoned at a depth of 4,001 metres below rotary table. Located 5 kilometres north of the WA-359-P permit boundary, Glatton-1 reached a total depth of 2,985 metres in Middle Jurassic sediments. The Glatton-1 record includes reference to oil and gas indications in the basal Legendre Formation over a 93 metre interval. Almost 14 kilometres south of WA-359-P, Lacerta-1 was drilled in 1997. The well reached a total depth of 3,293 metres in Lower Jurassic sediments, and encountered gas and oil indications. In the same year (1997) the large, northeast trending Andromeda Horst block was tested by the Andromeda-1 well, located 23 kilometres northeast of Brigadier-1. The Andromeda-1 exploration well tested two objectives, a drape closure of Middle Jurassic sandstones beneath the regional sealing Base Cretaceous unconformity and a deeper horst feature containing Early Jurassic and Late Triassic sandstones. Good quality sandstones were encountered at all of the objective horizons but no hydrocarbons were encountered, although oil and mineral fluorescence was observed at the top of the Early Jurassic North Rankin Formation below 3,764 metres.

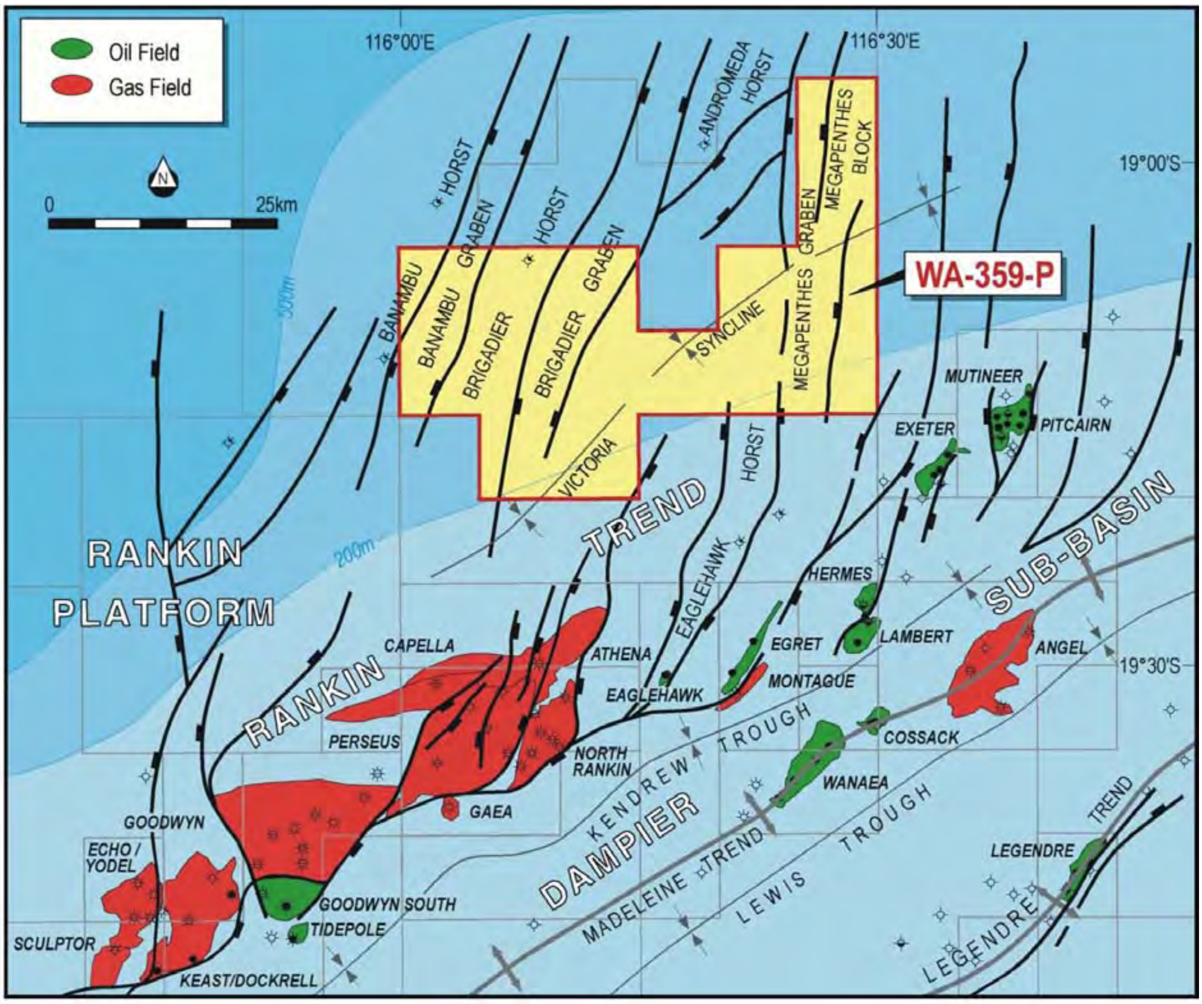

Figure 39. Structural Elements Map of the Northern Carnarvon Basin

The Northern Carnarvon, Brigadier-Rankin Platform – Structural Controls

Permit WA-359-P overlies the Brigadier Trend, a structurally positive feature, which forms a discrete sub-unit of the Rankin Platform. The Brigadier Trend is separated from the Rankin Trend gas and condensate fields by a narrow north-easterly trending trough termed the Victoria Syncline (Figure 39). The structural control mechanisms, which generated the basic elements of the geology, and which would eventually define the present day architecture of WA-359-P, began in the Late Permian. Subsequent "break-up" of these earlier elements during the Callovian, led to the development of a large number of Mesozoic sub-basins along the northwest margin of Australia. In the greater area of WA-359-P, the largest tectonic unit was expressed as the North Carnarvon Basin. Continuous crustal extension within the Northern Carnarvon Basin occurred differentially, leading to rifting and subsidence of the Barrow-Dampier Sub-basins and uplifting of the Ranking Platform. In turn the Rankin Platform itself was subjected to differential extension, creating a series of *en-echelon* northward plunging fault bound blocks, with the bounding faults themselves trending northeast-southwest and also north-south.

The giant gas, gas condensate and oil fields which occupy the structural apices of the Rankin Trend, nearly all possess a northerly dipping structural flank which results in a thickening of the Jurassic section northward into the Victoria Syncline. This effect is the result of the uplift and exposure of the southern most flanks of the Rankin Trend structures during the Early and Middle Jurassic. Erosion in some cases has brought about the removal of up to 1 kilometre of sedimentary section, this process is particularly evident at the southern extremities of the Rankin Trend structures.

Within the boundaries of WA-359-P and areas adjacent to the Victoria Syncline, the erosional reduction of the high standing structures has not been as severe as that encountered 50 kilometres to the south on the Rankin Trend fields. Two major tectonic events influenced the detailed structural architecture within WA-359-P and that of the Rankin Platform. The first of these was expressed as a general east-west extensional event, which created the permit wide north-south elongate troughs which are particularly evident in the time and depth structure maps below the regional seal, here represented by the Base Cretaceous Unconformity. The second tectonic event, was a later phase of northeast to southwest faulting which cut the earlier north-south fault trends, leading to structural interference with the earlier trend and the creation of numerous major and minor faulted sub-blocks and terraces. All of the structural mapping conducted on the pre-Cretaceous horizons, shows that the confluence of the two faulting phases has created four major north-easterly trending fault blocks or horst complexes which enter WA-359-P from the north. From the east, the first of these is the Megapenthes Block which appears to have suffered the least erosion and may be draped by Late Jurassic, Angel Formation sandstones, a geological outcome which is in evidence to the east at the Mutineer-Exeter Field. The second is the Andromeda Horst, a feature that loses structural amplitude as it extends into the central area of the permit. The third is the Brigadier block complex – a major horst that occupies much of the western sector of WA-359-P. Lastly, the Banambu block which occupies a small sector of the most north-westerly corner of WA-359-P.

The growth of the ocean spreading centre to the north of the Rankin Platform, brought about the thermal collapse of the crustal scale underpinnings of the North Carnarvon Basin and indeed much of the North West Shelf, creating a passive continental margin along the western boundary of the Australian landmass. Onto this subsiding margin, a massive pile of Late Cretaceous and Tertiary sediments of significantly or wholly carbonate affinities, stepped out into the deep offshore and eventually prograded onto the farthermost reaches of the Exmouth Plateau, 400-500 kilometres distant from the Rankin Trend.

The disposition of present day bathymetry within and adjacent to WA-359-P, is mirrored in the clinoform geometry of the underlying Holocene and Tertiary sediments which immediately precede it. Present water depths in WA-359-P range from 160 metres in the south easternmost corner of the permit, to 340 metres in the far north westernmost corner of the permit - Figure 39.

The Brigadier – Rankin Platform - Stratigraphy

Exploration to date, in the immediate region of WA-359-P i.e. on the Brigadier – Rankin Platform, has encountered sediments no older than the Triassic-Mungaroo Formation. The following examination of the stratigraphic potential of the WA-359-P block for producing commercial hydrocarbon accumulations will therefore be examined formation by formation beginning with the Triassic-Mungaroo Formation.

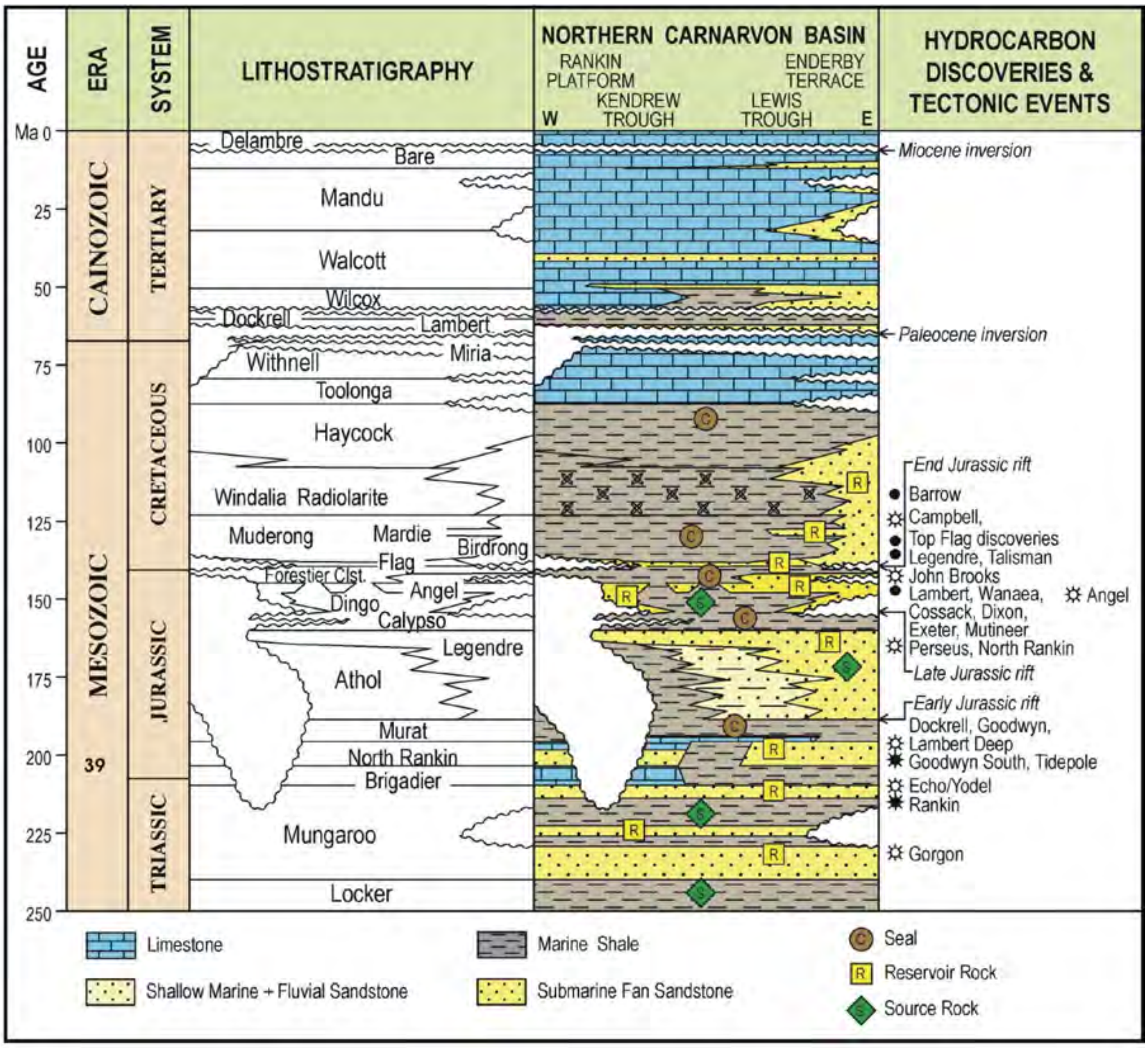

Figure 40. Generalised Stratigrphy Northern Carnarnon Basin

Stratigraphy - The Major Hydrocarbon Play Elements - Described Formation by Formation

The stratigraphic nomenclature for the sedimentary section resident in permit WA-359-P is presented in Figure 40.

The following analysis examines the essential key play elements offered by each major stratigraphic formation, which in turn determines its prospectivity for the accumulation of hydrocarbons.

Mungaroo Formation

The Mungaroo Formation is a sequence of delta top, coastal plain and fluvial claystones, siltstones and sandstones, best known as the primary reservoir for the giant gas and condensate accumulations along the Rankin Platform edge – the Rankin Trend. On examination the sandstones of the Mungaroo Formation are fine grained, to pebbly and kaolinitic. These sandstones become silica cemented with depth. They form extensive bodies, typically thirty metres thick, five to ten kilometres wide and tens of kilometres long. The interbedded floodplain claystones and coals of the Mungaroo Formation are most likely to be source rocks for gas, although oil-prone shales have been identified near the Rankin Platform. Sandstone reservoirs of the Mungaroo Formation contain gas and condensate in the Gorgon, West Tryal Rocks, Dionysus and Chrysaor Fields and in the North Rankin and Goodwyn Fields. Mungaroo Formation sandstones also act as an oil reservoir in part at the Goodwyn Field, at Dockrell-1, Tidepole-1 and the Leatherback-1 locations. At Banambu-1 the Mungaroo Unit "E" Sandstones had an interpreted porosity of 19% with a measured net to gross of 70%, but on analysis of the electric log suites were found to be water wet at this location.

Brigadier Formation

The Brigadier Formation is a sequence of thinly interbedded, transgressive marine sandstones and organically rich shales, which conformably overlie the Mungaroo Formation in the area of WA-359-P.

The Brigadier Formation was deposited in a relatively high-energy, shallow marine shelf environment, conducive to the development of significant reservoir potential. The very fine clastic content of the formation is considered to represent potential for a liquid prone source rock, where it has been penetrated in the Dampier Sub-basin. For example, at the Andromeda-1 location, these fine clastics are considered "fair to good" quality source rocks with the potential to produce gas and some oil. The Brigadier Formation reaches a maximum thickness of 420 metres at Gandara-1, 20 kilometres west of WA-359-P (Figure 41). At the Andromeda-1 location, the Brigadier Formation contained 91 metres of net sandstone which resulted from a formation net to gross ratio of 24%, the sandstones were interpreted to possess an average porosity of 18%; at the Banambu-1 location, the average log porosity in the Unit "D" sandstones was 17.5% with a net to gross ratio of 10%.

North Rankin Formation

The marginal marine sandstones of the North Rankin Formation encountered at Andromeda-1 (3,771-3,830 metres) possessed a net to gross ratio of 54% and an average porosity of 15%. Permeabilities displayed at this location and shared by the older Brigadier Formation ranged from 11 to 242 md.ft/cp.

Murat Siltstone Member

The Murat Siltstone Member is a dominantly fine-grained offshore marine unit which overlies the Mungaroo, Brigadier and North Rankin Formations. It corresponds to the lower Dingo Claystone of the older nomenclature and can contain some sandstone bedforms towards the base of the formation, at some locations. At the Banambu-1 location the Murat Siltstone was 46 metres thick.

The Murat Siltstone member provides a top seal for older Mungaroo Formation reservoir sandstones and where preserved, the younger sandstones of the Brigadier or North Rankin Formations.

Athol Formation

The Athol Formation conformably overlies the Murat Siltstone in the WA-359-P area, the formation is described in older nomenclature as the middle Dingo Claystone. It is generally represented by a fine-grained marine slope deposit that has some local and aerially restricted turbidite development. It ranges in age from the top of the *C. torosa* to the top of the *W. indotata* palynozone.

The Athol Formation was deposited in a lower energy, offshore marine setting with restricted circulation of the water column. It is a potential source rock and along with the underlying Murat Siltstone, is considered to be the regional seal for the Brigadier and North Rankin Formation sandstone play. At the Andromeda-1 location the Athol Formation is described as having "fair to good" quality source rock potential; the section between 3,428.5 and 3,641 metres being of good to very good quality, with Hydrogen Indices ranging from 145 to 244.

Legendre Formation

The Legendre Formation has not been identified unequivocally in all of the well data adjacent to WA-359-P, its local absence may be due to the well locations having been sited on the highest standing structural closures of the presently tested prospectivity. In Glatton-1 a 75 metre interval of sandstones and shales is interpreted to belong to the basal Legendre Formation and to subcrop the Callovian unconformity. Elsewhere in the basin it is represented by pro-delta, and lower delta plain sediments with locally well developed stacked channel sandstone bodies. At the Andromeda-1 location, Legendre Formation sandstones were encountered between the depths of 2,755 and 3,279 metres. The sandstones exhibited a 60% net to gross ratio and an average porosity of approximately 19%, the average permeabilities ranged 214 to 3,288md.ft/cp. The Legendre Formation at Andromeda-1 did not contain any hydrocarbon indications.

Calypso Formation

The Calypso Formation is a Callovian sandstone unit of *W. digitata - R. aemula* palynological age. It can be correlated to the Biggada Sandstone at the Barrow Deep-1 location on Barrow Island. At this location the sandstone consisted of massive clean, quartz sandstone, medium to very coarse grained and sometimes granular, with porosities of 20% and permeabilities of 18 millidarcies. The pay thickness at this location was 24 metres; the formation top was encountered at approximately 3,230 metres. At the southern end of Barrow Island, at the Perentie-1 location, the Biggada Formation was encountered at 3,539 metres sub-sea and contained high-pressured gas shows. To the north, in the Dampier Sub-basin, the time equivalent Calypso Formation hosts hydrocarbons at the Perseus Field location; a partially down thrown structural and stratigraphic trap which lies between the giant gas fields of Goodwyn to the west and North Rankin to the east. Calypso Formation reservoirs are also present at the Capella-1 location, on the Goodwyn Block to the northwest of the Perseus Field. The Calypso Formation has not been identified in the presently available well data adjacent to WA-359-P, but it may be present in the Victoria syncline.

Dingo Claystone

The Late Jurassic Dingo Claystone is a post-rift, deep marine, organic rich claystone. The oldest of this Dingo Claystone sequence is Oxfordian (*W. spectabilis* zone), while the youngest is resident in the *P. iehiense* palynozone. It is the proven source unit for the Barrow, Dampier and Exmouth Sub-basins, and where present it averages nearly 2% Total Organic Carbon (TOC).

The combined thickness of the Murat Siltstone, Athol Formation and the Dingo Claystone is greater than 5 kilometres in the northern part of the Barrow Sub-basin, and it reaches as much as 4 kilometres in the centre of the Exmouth Sub-basin. Elsewhere and specifically along the Rankin Platform and the Alpha Arch, the Murat Siltstone and the Athol Formation are partially eroded and may be completely missing from the high-standing Triassic blocks. The Dingo Claystone has not been identified in the presently available well data adjacent to WA-359-P, but it may be present in the Victoria syncline.

Forrestier Claystone - Barrow Group Equivalent

The Barrow Group deposits consist of three depositional units: topsets, foresets and bottomsets. The topset sediments were deposited in fluvial to shallow marine environments, the foreset sediments were deposited on the submarine delta front slope and the bottomset sediments were deposited on the deep sea-floor in front of the slope.

The Barrow delta itself prograded towards the north, so that the different depositional units of the Barrow Delta Group, young in a northerly direction. The water depth over the foresets probably ranged from about 200 to 500 metres, and the bottomsets were deposited in water from 500 to more than 1,000 metres deep.

The Forrestier Claystone encountered at the Andromeda-1 location was 11 metres in thickness, it represents an approximately time equivalent sedimentary accumulation to the entire Barrow Group deltaic sediments described above, and it was deposited oceanward of the Barrow Delta complex.

Muderong Shale and other Cretaceous Sediments

The Muderong Shale is a transgressive marine unit which overlies the Barrow Group and its equivalents. It consisted of claystone and calcareous claystone lithologies at the Banambu-1 location, where it attained 43 metres in thickness. Samples analysed from this section reveal little source rock potential, but the formation is considered to provide a regional sealing capacity. At the Andomeda-1 location, the Muderong Shale attained a thickness of 21 metres. Where it laps onto the Rankin Platform, it provides a top seal to the underlying Mungaroo Formation gas and oil accumulations located at the Dockrell, Eaglehawk, Goodwyn, Rankin and Tidepole Fields.

The succeeding Windalia Radiolarite records a regional radiolarite acme. The Haycock Marl overlies the Windalia Radiolarite and was deposited in an outer shelf to slope environment as one of a number of low angle prograding pulses within an overall aggradational system. The overlying Toolonga Calcilutite is the first of a sequence of regional wedges of almost completely carbonate dominated lithologies. At the Andromeda-1 location the Toolonga Calcilutite attained a thickness of 108 metres. The remaining Cretaceous is composed of similar lithologies deposited within the Withnell and Miria Marl formations.

Tertiary sediments

The Tertiary sediments are mainly carbonates and calcareous claystones deposited in cycles of shelf edge progradation and transgression caused by sea level fluctuations and tectonism. The carbonate shelf edge built out across the subsiding Exmouth, Barrow and Dampier Sub-basins, the Alpha Arch and the Rankin Platform, but it did not reach the Exmouth Plateau - where only thin deep-water Tertiary sediments are present. Quartz sandstones are present in the Trealla Limestone of Miocene age. From the Miocene to Recent, the carbonate shelf edge prograded dramatically, providing some of the thermal blanket, along with the earlier Tertiary and Cretaceous sediments, which enabled the deeper source rock sequences to reach a degree of thermal maturation necessary for oil and gas generation and expulsion.

Hydrocarbon Play Types and Prospectivity in WA-359-P

The prospectivity of the Brigadier – Rankin Platform region has been increased in recent years by the extensive exploration effort and success obtained in the Mutineer-Exeter Field area to the southeast and the giant hydrocarbon finds to the southwest in the Io –Jansz Field locations.

The play types resident in the permit WA-359-P fall into three major groupings:

- Late Jurassic – Eliassen Formation and Angel Formation stratigraphic traps
- Middle Jurassic – Legendre Formation - Unconformity Subcrop Traps
- Early Jurassic/Triassic – North Rankin/Mungaroo - Structural Traps

These play types can be readily identified on the 3,100 kilometre Michelle 2-D seismic data which was acquired in late 1993 and covers WA-359-P with an approximately two by four kilometre seismic grid.
Ten leads have been identified within WA-359-P in three main play types, described above.

Late Jurassic – Eliassen Formation and Angel Formation Traps.

There are two primary reservoir targets within the Late Jurassic, they are the Oxfordian Eliassen Formation sandstones and the later Kimmeridgian through Berriasian Angel Formation sandstones.

The older Eliassen Formation sandstones are considered to be shoreface sandstone bodies, which trend northeast to southwest along a palaeo-shoreline which passes through the Io/Jansz gas field, where the early wells demonstrated sandstones of 50 to 62 metres of thickness, of these outer shoreface sandstones. Remnants of this sandstone trend occur at the Malus-1 location, where the sandstones are 20 metres thick and at the Eastbrook-1 location where the sandstones were 8 metres thick and are considered to have been deposited northwestwards through block WA-359-P.

Exoil has identified three Eliassen Formation leads, they are the ZF N, ZF NE and the ZF W Leads, these leads are depicted on Fig.41.

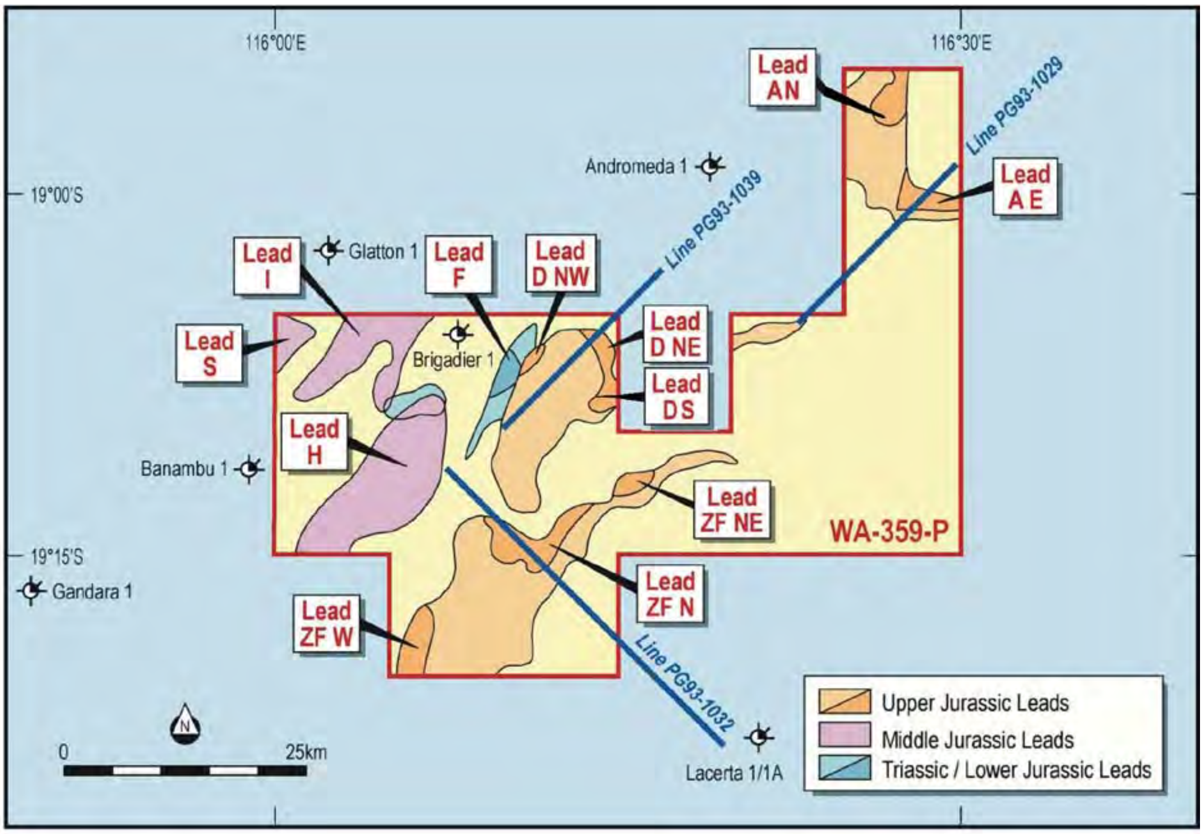

Figure 41. WA-359-P Leads Map

The figure indicates that the leads are an interrelated series of stratigraphic pinchouts or zero edge thicknesses of the presumed distribution of the Eliassen Formation. The Eliassen Formation is considered to have been deposited within the present Victoria Syncline, from which it thins and eventually laps out onto the flanks of the Brigadier horst complex. The three closures share a common closing contour at a depth of 3,540 metres subsea.

A seismic line depicting the ZF N lead is shown in Fig.42.

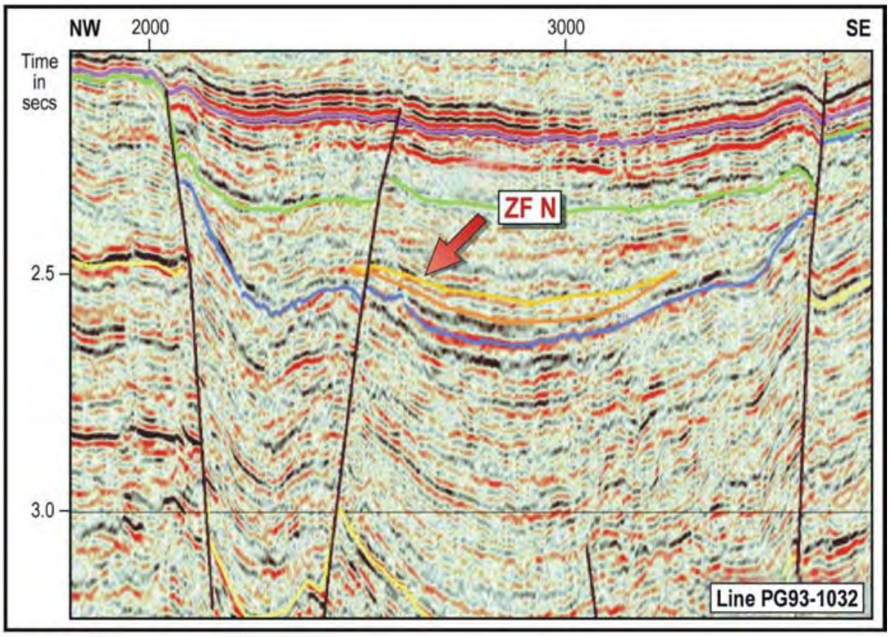

Figure 42. Seismic Line PG93-1032 Showing ZF N Prospect

A further objective reservoir is present within the younger sandstones of the Late Jurassic, Angel Formation. On seismic evidence, these sandstones are predicted to occur in the Victoria Syncline in the central and eastern part of WA-359-P, but were probably never deposited on the more elevated Banambu and Brigadier horsts to the west. The reservoir sandstones in the Mutineer - Exeter Oil Field which contain 61 million barrels of oil, are located in immediately adjacent acreage to the east, and belong to the Late Jurassic - Angel Formation.

The lead inventory for the Angel Sandstone closures is also presented on Fig.41. The leads total five in number, they are: the AE, AN, D NE, D NW, and DS Leads. A seismic cross section over the AE Lead is shown in Fig.43, it illustrates the location of the Angel Sandstones within the seismic packet - Base Cretaceous to Main Unconformity, the two seismic horizons coalescing or "pinching out" on to the gently faulted and folded high to the right hand side of the figure. All of the leads in the "A" grouping have a location within the faulted synclinal feature lying between the Megapenthes Fault Block and the Andromeda Horst. The stratigraphic pinchout to each culmination is achieved by the updip lap out of the Angel Formation onto the adjacent highs. Each culmination at the AE, AN and adjacent leads to the west, shares a common closing contour at a depth of 3,100 metres sub sea.

A seismic line (PG93-1029) demonstrating Lead AE is shown on Figure 43.

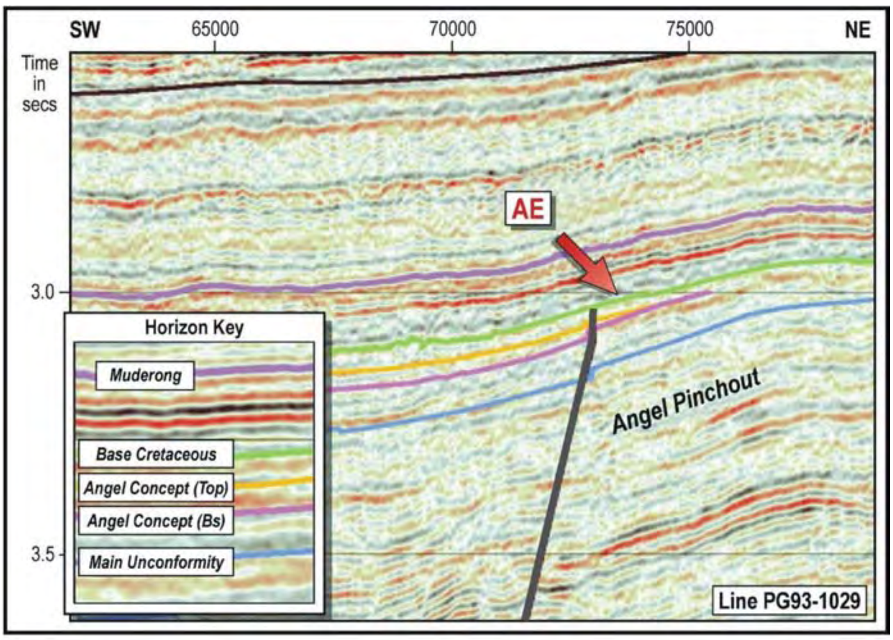

Figure 43. Seismic Line PG93-1029 Showing AE Prospect

The cluster of Angel Formation leads denominated D NE, D NW and DS, lies southeast of and contiguous with the "A" Grouping along the northern flanking terraces of the Victoria Syncline, immediately eastwards of the Brigadier Horst.

Lead D NW and D NE occupy the same grabenal downthrown terrace feature. The pinchout of the mapped Angel Formation defines the "D NE" culmination to the north east and the pinchout to the northwest against the flank of the Brigadier Horst defines the culmination of the D NW Lead. The depositional model envisaged for this distribution is considered to be a sheet form turbiditic sandstone with derivation from the north and north east.

If the culminations of leads D NE and D NW are filled to the mapped closure defined by the 3,380 metres subsea contour then the combined closure could extend to an area of 61 square kilometres. If the closures are defined by the 3,250 metre subsea contour then the volume of defined closure at the D NE Lead becomes an interpreted 12.7 million cubic metres of rock volume. The closed rock volume at the D NE Lead becomes an interpreted 22.8 million cubic metres.

The Lead DS, lies on a separate bounding fault block immediately to the south of Lead D NE. Closure at the 3,250 metres subsea contour imparts an interpreted volume of 8.5 million cubic metres to this lead.

One of the "D" Group of leads as shown in Figure 41, is present on the seismic line PG93-1039, it is depicted in Fig.44 (below).The figure illustrates the pinchout of the Angel Formation northeastwards and updip into the D NE structural culmination, described above.

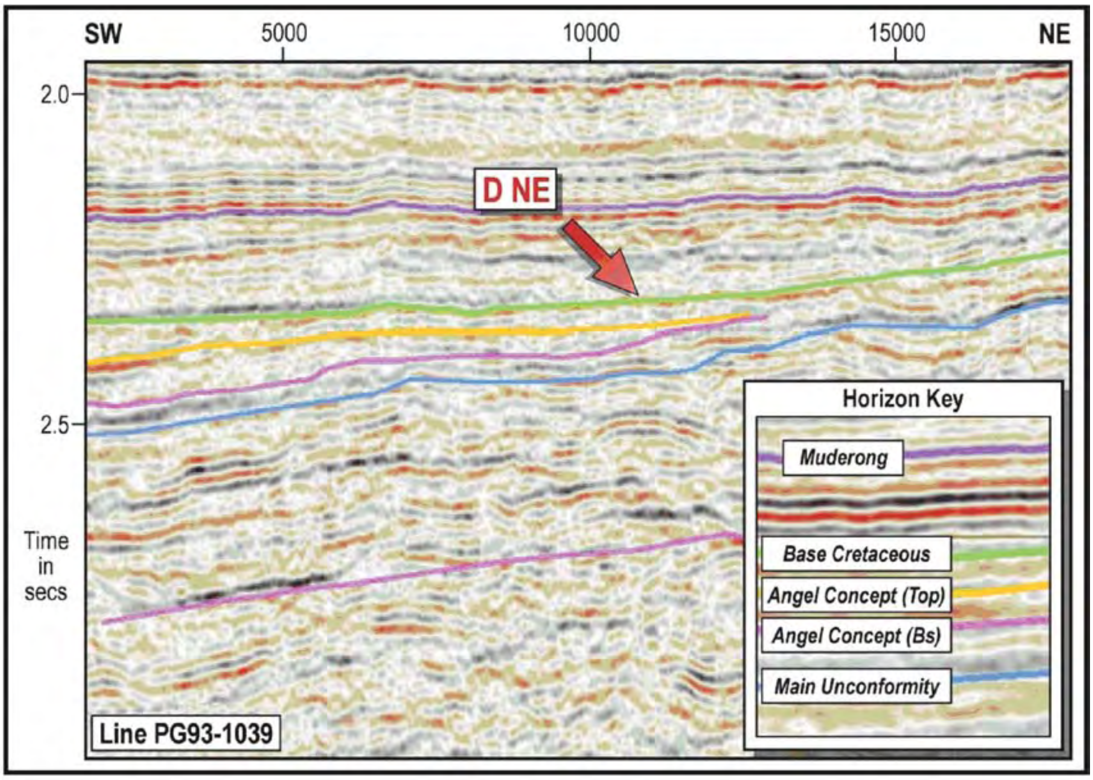

Figure 44. Seismic Line PG93-1039 Showing D NE Prospect

Middle Jurassic – Legendre Formation - Unconformity Subcrop Traps

The primary reservoir objective of the Middle Jurassic unconformity traps are the subcropping sandstones of the Legendre Formation, an established hydrocarbon productive reservoir along the Rankin Trend. In acreage nearly adjacent to WA-359-P, the Legendre Formation provides the reservoir for the giant Perseus gas and condensate field lying between the giant Gorgon Gas Field and the North Rankin Field. The Legendre and Angel plays are sealed by onlapping marine claystones of the Early Cretaceous Forrestier and Muderong Formations. The structural element of the Middle Jurassic unconformity traps is created by anticlinal drape closure over Jurassic horsts and footwall blocks. The limited faulting is related to compaction, Early Cretaceous extension and Late Tertiary transpression.

Exoil has identified three Middle Jurassic unconformity trap leads within WA-359-P (Figure 41):

The first of these traps described here is the "S" Lead, it is located in the northwest of WA-359-P on the Banambu Horst (Figure 41). It is defined by good quality 2-D seismic data which has been correlated with three wells in the area; Brigadier-1, Banambu-1 and Glatton-1. The use of these well ties, both for the calculation of the depth to the top of the Legendre Sandstone subcrop updip of the Glatton-1 well location, and the extension of structural closure towards the Banambu-1 location to the south, is considered to have enabled a confident prediction.

The hydrocarbon trapping mechanism for the "S" Lead comprises a weakly faulted anticlinal structure, with a potential closure of 17 square kilometres, which is interpreted to contain subcropping basal Middle Jurassic, Legendre Formation reservoir sandstones sealed by onlapping Early Cretaceous, Muderong Formation claystones. Structurally the "S" Lead marks the crestal position on the Banambu horst block, with bounding fault seal on the northwest and southeast facing flanks. The remaining dip closure is provided by axial dip north-eastwards towards the Glatton-1 location and axial dip south-westwards towards the Banambu-1 location. The fault bound flanks are considered to be sealed by younger Early Cretaceous shales of the Muderong Formation. The "S" Lead is located administratively within two separate West Australian permits; the central and updip area, lies within WA-359-P, but the northern extension immediately updip of Glatton-1 and a western lobe both extend into block WA-389-P to the north and west. Most of the sandy, Middle Jurassic, Legendre Formation is considered to have been eroded from the Rankin Platform with the creation of the Callovian unconformity. The effect of the Callovian unconformity is amply demonstrated at the Banambu-1 location where an angular unconformably separates Early Cretaceous, Muderong Formation, marine claystones from underlying marine claystones of the Middle Jurassic, Athol Formation. Seismic evidence indicates a thickening interval of Legendre Formation beneath the Callovian unconformity northwards along the Banambu Horst. The well Glatton-1 proved the presence of basal Legendre Formation reservoir sandstones beneath the angular unconformity. These sandstones were reported to contain oil shows over a 93m interval between 2,810 and 2,903 metres below rotary table (Woodside Well Completion Report - Glatton-1 Basic Data, 2000), indicating the existence of a working hydrocarbon charge system.

The main risk elements assigned to the "S" Lead are access to sufficient migrating hydrocarbons, particularly from the north and the presence of good quality reservoir sandstones updip of Glatton-1 at the crest of the Banambu Horst.

The "S" Lead lies in water depths of between 300 and 350 metres.

A second Legendre lead has been defined at the "I" location, a closure resident between the Banambu Horst to the northwest and the Brigadier Horst to the south east. The lead rests within a saddle-like synclinal feature between the two horsts. Closure and sealing against the confining horst footwall blocks is therefore required for this lead to maintain any incipient charge of hydrocarbons through geologic time. The Perseus Field and the Persephone discovery well indicate that this model of petroleum accumulation is possible in the area.

The operator has measured a closed area of 61 square kilometres for this feature.

The remaining Legendre lead occupies the southern extremity of the Brigadier Horst within WA-359-P.
The "H" Lead is a purely structural trap within a footwall setting. It lies immediately southwestwards of the Brigadier-1 location on the Brigadier Horst (Figure 41). It is defined by good quality 2-D seismic data which has been correlated with the Brigadier-1 well.

The reservoir in the "H" Lead is considered to be represented by the Legendre Formation. In the adjacent well, Andromeda-1, the Legendre Formation measures 300m of thickness.

The structural closure in the "H" footwall trap covers an area of 72 square kilometres, an area which is almost completely resident within permit WA-359-P. The trap requires fault sealing on the west and eastern flanks of the structure. The remaining closure is obtained by the natural axial dipping surface of the Athol Formation Shale to the north beyond Brigadier-1 and by the loss of structural amplitude on the Brigadier Horst, as it dips southwards in to the Victoria Syncline. The "H" Lead, is easily identified as an area clearly updip of the early 1978 Brigadier-1 exploration well, which at the time was the first well to be drilled in the area.

The presence of ditch cutting hydrocarbon fluorescence in Early Jurassic and older sediment samples below 3,340 in Brigadier-1, and both ditch cuttings and side-wall cores from 3,760 to 3,820 metres in Andromeda-1 may indicate migration and or generation of hydrocarbons in the immediate area.

The main risk element presently assigned to the "H" Lead, is the effectiveness of hydrocarbon migration mechanisms to fill the available closed volume of the structure.

The "H" Lead lies in water depths of around 300 metres.

Early Jurassic – Triassic Structural Traps

The Athol Formation is an extensive shale unit that provides an effective top and lateral seal for hydrocarbons entrapped in the underlying North Rankin Formation and the deeper and older sandstones of the Mungaroo Formation. The effectiveness of this structural trap style is amply demonstrated by the Lambert-2 accumulation described above.

Two Early Jurassic–Triassic structural leads are presently identified in WA359P (Figure 41):

The first of these is to be found within and below the structural closure defined by the Legendre Formation Lead "H", described above. The deeper North Rankin/Mungaroo Formation lead resides in a relatively confined area located at the northern extremity of the "H" Lead. This lead has not been identified by a separate Lead identifier name in Fig.41.

The adjacent lead to the east – "F" Lead, partially underlies the D NW Late Jurassic Angel Formation sandstone reservoir objective. The target lies immediately to the east of the Brigadier-1 location, in a downthrown subterrace occupied by the D NW Lead and its greater extension, the "D" Group of leads. The "F" Lead reservoir objective is considered to be Mungaroo Formation in age or possibly a North Rankin Formation Sandstone objective. In the adjacent wells Brigadier-1 (5.0 kilometres to the northwest) and Andromeda-1, (20 kilometres to the northeast) the North Rankin Formation is 100 metres thick with up to 30 metres of net sandstone.

The presence of ditch cutting hydrocarbon fluorescence in Early Jurassic and older sediment samples below 3,340 metres in Brigadier-1, and both ditch cuttings and side-wall cores from 3,760 to 3,820 metres in Andromeda-1 may indicate migration and or generation of hydrocarbons in the immediate area.

The main risk element assigned to the “F” Lead is the access to sufficient migrating hydrocarbons from shallower oil prone source rock sections into the older Mungaroo reservoir sandstones, However, the migration pathway from the Victoria Syncline to the south should be relatively unimpeded. Maturation and migration of hydrocarbons generated in the deeper gas prone Triassic source rocks maybe relatively straightforward.
The “F” Lead will require fault seal against the bounding Brigadier Horst footwall section.

The “F” Lead lies in water depths of around 300 metres.

Exploration and Expenditure Programmes

The company has proceeded through the first two years of a three-year term of the WA-359-P license obligations The company has met its commitment to purchase and reprocess 2-D seismic data to an expenditure of A$300,000. Interpretation of this seismic data has been completed. Regional time and depth maps have been constructed and integrated with well information. Prospect mapping is complete and prospect packages have been prepared. A scoping economic study for potential hydrocarbon accumulations within the permit has also been completed. In the third year of the first permit term the company will acquire a new 2-D seismic survey of 250 line kilometres and process it. This part of the commitment programme will be met by MEO Australia Limited. MEO will earn a 60% interest in the permit by acquiring the year 3 commitment seismic in the permit and electing to fund 90% of the cost of drilling the first exploration well in the permit, MEO could earn up to a 70% interest, depending on the percentage the current permittees elect to contribute to the well cost. MEO has elected to drill this well. If Exoil elects to contribute to 5% of the cost of the well it will hold a 20% interest in WA-359-P. The data sets will receive extensive interpretational effort so that, should the company so decide, it can elect to enter a second three year permit term in which it has indicated it will drill one well and acquire further seismic data.

In the opinion of the author the company has developed and committed to a satisfactory and clearly defined work programme, which is reasonable having regard to the stated objectives of the company.

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GLOSSARY OF TECHNICAL TERMS AND ABBREVIATIONS

Airborne Magnetics Measurement of the earth's magnetic field from a surveying aircraft, for the purpose of recording the magnetic characteristics of rocks.

Anticline An upwardly convex fold.

A$ Australian dollar.

Barrel (BL) 159 litres, 42 US gallons or 35 imperial gallons.

Bcf One billion cubic feet (of gas) 1,000,000,000 (109).

BOPD Barrels of oil per day.

Condensate Hydrocarbons associated with natural gas that are liquid under surface conditions and gaseous in the subsurface.

DST Drill stem test.

Farmin Where a company acquires an interest in an area from another company in return for payment of all or part of the company's exploration commitments.

Fault A fracture surface or zone in a rock along which movement has taken place.

Geochemistry The study of the abundance of elements in rocks or fluids by chemical methods.

Geophysics The methods which seek to locate hydrocarbon deposits by direct or indirect measurements of a large range of geophysical properties of the deposits or the rocks and fluids associated with them.

"HRDZ" or Hydrocarbon.

Related Diagenetic Zone The occurrence of vertical hydrocarbon seepage through rocks causes compositional changes, usually carbonate deposition, which can be seen on seismic sections as high velocity zones.

Hydrocarbon Accumulation An in-situ occurrence of oil or gas which may or may not be produced economically.

Isochore Shows vertical thickness and distribution of a certain mapping interval.

Km Kilometre(s).

Lead Anomalous structural or stratigraphic feature not sufficiently defined by geological or geophysical means to classify it as a drillable feature.

LPG Liquefied Petroleum Gas.

MaBP Millions of years before present.

MMbl Millions of barrels.

MMcf Millions of cubic feet per day.

Net Pay Reservoir rock containing movable hydrocarbons.

Prospect Anomalous structural or stratigraphical feature sufficiently defined or mapped geologically and geophysically to classify it as a drillable feature.

Reservoir A porous bed of rock that has the ability to contain oil and gas.

RFT Repeat formation test.

RT Measured from the rotary table.

Seal Necessary requirement of a sedimentary rock such that it can impede the progress of migrating hydrocarbons.

Seismic A geophysical technique to measure structural and stratigraphic characteristics of subsurface rocks using surface energy sources. Shock waves produced at the surface penetrate the subsurface and are reflected off the rock interfaces back to the surface, where sophisticated recording and processing technologies allow one to map the subsurface geology to be mapped.

Source Organic matter contained in a rock, which when sufficiently buried will generate hydrocarbons.

SS Measured from sea surface.

Tcf One trillion cubic feet (of gas) 1,000,000,000,000 (10^{12}).

TVD Measured true vertical depth.

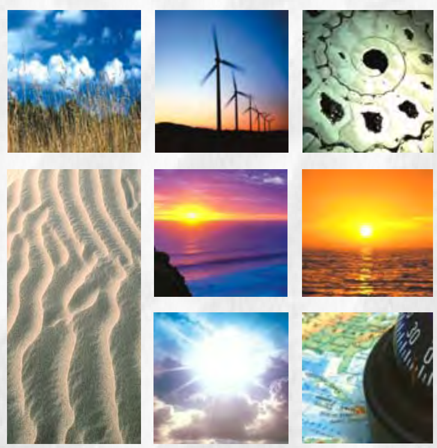
2-D and 3-D Seismic A geophysical technique measuring time for a sound wave to travel into the earth and return which is used to display subsurface structure in the two dimensional sense.

US$ American dollar.

Competent Person's Report on WA-332-P and WA-333-P Permits, Browse Basin, Australia

Prepared for

Exoil Ltd



Date: 7th November 2008

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Competent Person's Report on WA-332-P and WA-333-P Permits, Browse Basin, Australia

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1. EXECUTIVE SUMMARY

Exoil Ltd has contracted RPS Energy Pty Ltd (RPS) to provide a competent persons report on the WA-332-P and WA-333-P permits, awarded on the 1st of October 2002 and an independent evaluation of the Braveheart Prospect located in the central-northern part of the combined permit area. A summary of the details of the WA-332-P and WA-333-P permits is presented in Table 1.

In addition to the Braveheart prospect, three other leads have been identified within the blocks (Figure 1), however, only the Braveheart prospect has been evaluated in detail. Therefore, the focus of this report is the Braveheart Prospect, a stratigraphic play consisting of an *M. australis* reservoir sandstone pinchout within the Barremian aged Echuca Shoals Formation. The current prospective resources calculated for this prospect are summarised in tables 2-5.

Permit	Operator	% Interest	Status	Licence Expiry Date	Total Permits Area (Km^2)	Comments
WA-332-P and WA-333-P	Exoil Limited	100%	Exploration	Application for extension	6,145	Exploration

Table 1 - Summary Table of Permits

Oil Case	Prospective STOIIP (mmbbls)				Risk Factor	Operator
WA-332-P and WA-333-P	Low Estimate	Best Estimate	High Estimate	Mean Estimate	COS %	Exoil Limited
Braveheart Prospect	516	1335	2957	1572	12	

Table 2 - <u>Oil Case</u> Prospective STOIIP Braveheart Prospect

Oil Case	Prospective Recoverable Oil Resources (mmbls)				Prospective Recoverable Associated Gas (bscf)				Risk Factor
WA-332-P and WA-333-P	Low Estimate	Best Estimate	High Estimate	Mean Estimate	Low Estimate	Best Estimate	High Estimate	Mean Estimate	COS %
Braveheart Prospect	150	397	897	472	28	78	184	95	12

Table 3 - <u>Oil Case</u> Prospective Recoverable Oil and Associated Gas Braveheart Prospect

Gas Case	Prospective GIP (bscf)				Risk Factor	Operator
WA-332-P and WA-333-P	Low Estimate	Best Estimate	High Estimate	Mean Estimate	COS %	Exoil Limited
Braveheart Prospect	730	1895	4217	2231	12	

Table 4 - <u>Gas Case</u> Prospective GIP Braveheart Prospect

Gas Case	Prospective Recoverable Gas Resources (bscf)				Prospective Recoverable Condensate (mmbbls)				Risk Factor
WA-332-P and WA-333-P	Low Estimate	Best Estimate	High Estimate	Mean Estimate	Low Estimate	Best Estimate	High Estimate	Mean Estimate	COS %
Braveheart Prospect	501	1322	2973	1564	23	64	153	78	12

Table 5 - <u>Gas Case</u> Prospective Recoverable Gas and Associated Condensate

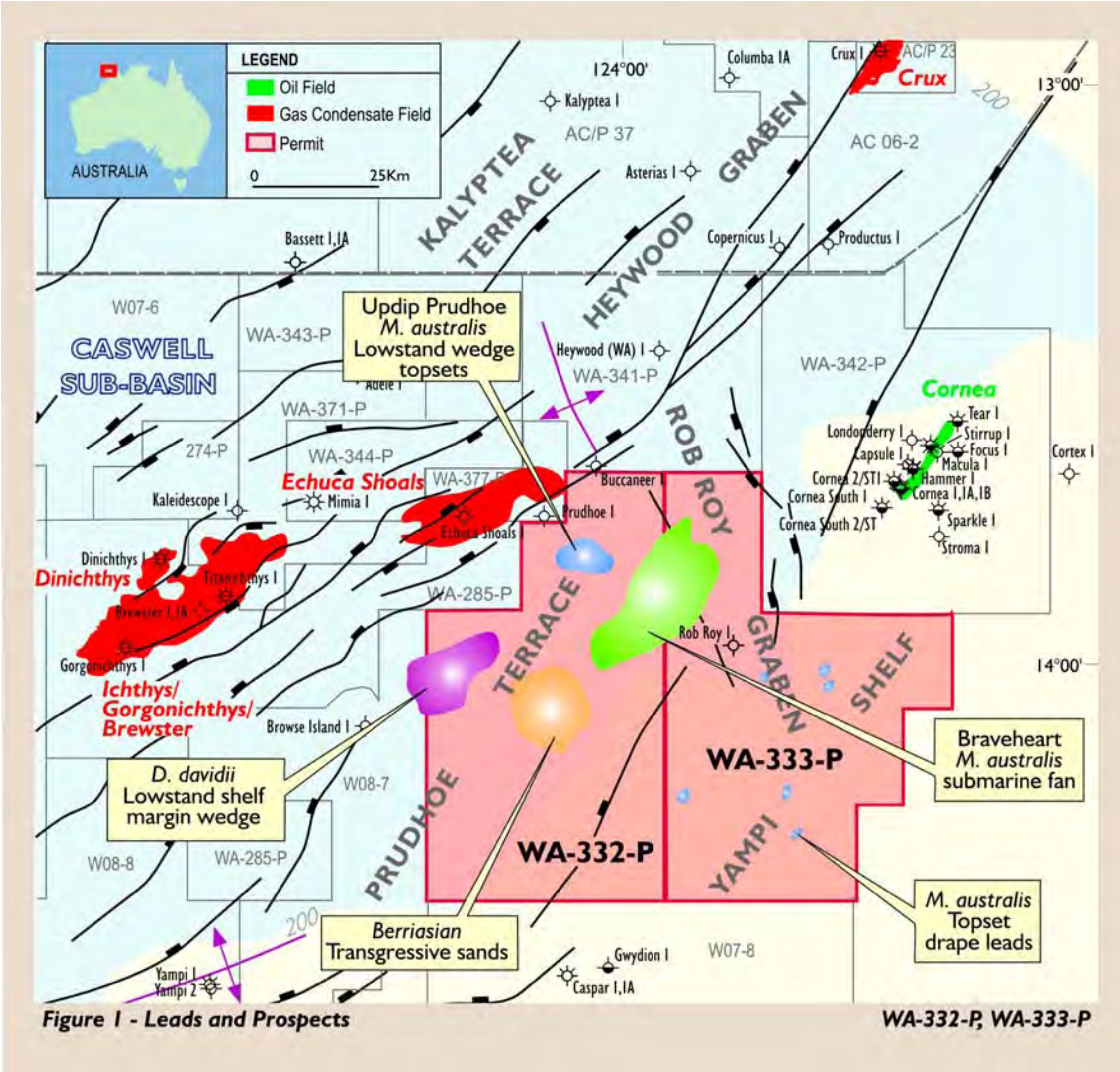

Figure 1 - Leads and Prospects Interpreted in the WA-332-P and WA-333-P Permits

2. INTRODUCTION

2.1 Description of Permits and Licence Commitments

The WA-332-P and WA-333-P permits combined cover a total area of 6,147 km^2. They are located within the relatively under explored Browse Basin, on the border of the Yampi Shelf and the Prudhoe Terrace, south of the Heywood Graben. The Ichthys gas accumulation lies nearby to the northwest and the Cornea oil and gas field to the east (Figure 2). South of the permits, the Caspar 1A and Gwydion-1 wells are currently non-commercial oil and gas discoveries.

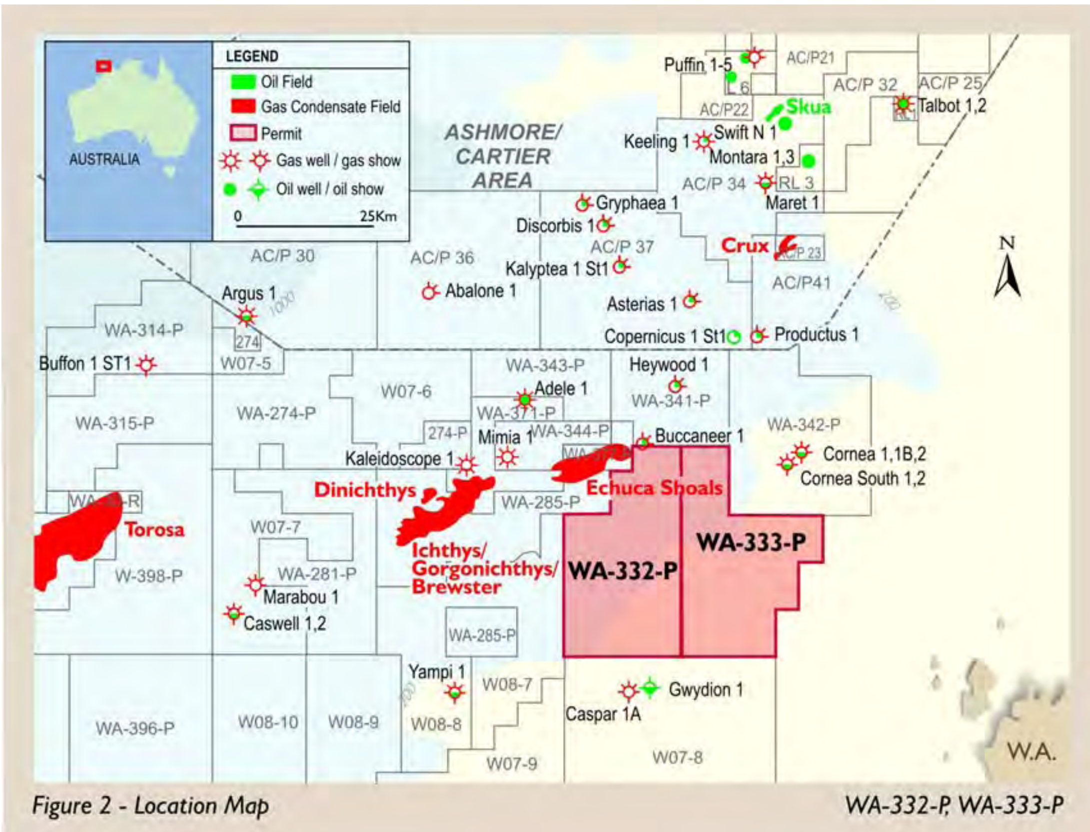

Figure 2 - Location Map (*modified from Australian Government, Department of Resources, Energy and Tourism*)

The WA-332-P and WA-333-P permits were granted on the 1st of October 2002 with identical work programs (Table 6).

Year	Activity	Status
1	• Data collection and geoscience studies	• Completed
2	• Seismic interpretation and geoscience studies	• Completed
3	• 1000 km new 2D seismic	• Completed; acquired 1872 km
4	• Seismic interpretation and geoscience studies	• Completed
5	• Petrophysical and AVO analysis	• Completed
	• One well in each permit	• In progress
6	• 800 km new 2D seismic	• Application to complete in Year 5

Table 6 – WA-332-P and WA-333-P work programs

2.2 Exploration History

The Browse Basin is one of the least explored basins along Australia's North West Shelf, hosting significant undeveloped reserves of gas and condensate in the Scott Reef (Torosa), Brecknock, Brecknock South (Calliance), Ichthys, Crux and Argus Fields. These combined with a number of other smaller hydrocarbon discoveries (Adele 1, Caspar 1A, Gwydion 1, Echuca Shoals 1, Psepotus 1 and the Cornea oil and gas field) demonstrate the existence of an active and effective petroleum system in the basin.

Exploration in the Browse Basin commenced in 1963 with an aeromagnetic survey contracted by Woodside (Lakes Entrance) Oil Company. Drilling began in 1970 with the Leveque 1 well, which tested a stratigraphic play in the Leveque Shelf and was abandoned as a dry hole with minor hydrocarbon indications. This well was followed by the discovery of gas at Scott Reef -1 in 1971 within Early–Middle Jurassic (Plover Formation) sandstones and sandy dolostones of Late Triassic – Jurassic age on the southern culmination of a faulted anticline located on the Buffon–Scott Reef–Brecknock Anticline Trend. Three years later, in 1979, Brecknock 1 tested a broad anticline feature finding 68.3 m of net gas sandstone in Early to Middle Jurassic sediments.

Encouraging discoveries were reported during the early 1980s, including Brewster 1A ST1 (1980), Caswell 2 ST2 (1983) and Echuca Shoals 1 (1983), however the predominance of gas discoveries led to the basin being classified as gas-prone and between 1984 and 1994 the exploration focus shifted largely to the Heywood Graben in the northern Caswell Sub-basin (Gryphaea 1 (1987), Asterias 1 (1987), Discorbis 1 (1989) and Kalyptea 1 ST1 (1989)) and along the basin margin faults of the Leveque and Yampi shelves.

In 1995 Gwydion 1 was drilled by BHP on the Yampi Shelf and intersected three separate pay zones, one of which consisted of a 10-15m oil column. This discovery, although uneconomic, served to renew exploration interest in the Browse Basin and subsequent drilling resulted in the Cornea 1 oil and gas discovery (1997) drilled 12 km northeast to WA-333-P permit area, proving the oil potential of the basin.

Drilling in 2000 resulted in the discovery of another major gas and condensate accumulation in the central Caswell Sub-basin (Titanichthys 1, Gorgonichthys 1 and Dinichthys 1) and the extension of previously discovered gas provinces (Brecknock South 1 well and to the north, on the same structural trend, the Argus 1 well).

Targeting of Early Cretaceous lowstand fans and 'ponded' turbidite oil targets within the Caswell Sub-basin during 2001–2002 was unsuccessful (Carbine 1, Firetail 1 and Marabou 1 ST1 wells). In 2002 – 2003 Maginnis 1A ST2 tested the hydrocarbon potential of the deep-water Seringapatam Sub-basin, however no hydrocarbons were encountered.

Appraisal drilling of the Ichthys gas field was completed in 2003–2004 with the Ichthys 1A, Ichthys 2A ST2 and Ichthys Deep 1 wells.

The appraisal of the Crux gas field, (north of the permit areas), continued throughout 2006-2007 with the acquisition of a 3D seismic survey and the drilling of the Crux 2 and Crux 2 ST1 wells. Nexus Energy Ltd (2007) reports that the Crux 2 well confirmed a gross gas column of 70m with a net 26m of good quality sandstones in the Jurassic aged Plover Formation.

In June 2007, Woodside Energy Ltd drilled the Torosa 4 appraisal well and Snarf 1 exploration well (Petroleum Exploration Permit WA-275-P), which encountered no hydrocarbons and was plugged and abandoned as a dry hole.

2.3 Data Base

Rob Roy-1 is the only well to have been drilled within the WA-333-P permit area (Figure 3). This well was drilled in 1972 by BOC of Australia Ltd and tested an asymmetric feature, the Rob Roy Graben, with anomalous dip zone on the western flank. The well was plunged and abandoned as dry hole with no hydrocarbon bearing zone encountered. The well history is summarized in Table 7. A basic well completion report and log files from this well were made available for this study.

The central part of the WA-332-P permit area to date remains unexplored (Figure 3), however two wells have been drilled near the northern extent of the permit area, namely Buccaneer 1 and Prudhoe 1. The Prudhoe 1 well was drilled by BOC of Australia Ltd in 1974 to test a northeast-southwest fault-bounded structure within a horst-graben feature which includes the Heywood block and Rob Roy graben. The Middle Jurassic sequence was the primary target, and the well was plugged and abandoned at a depth of 3,322 m (Table 7). No hydrocarbon indicators were recorded and no reservoir tests were run. Buccaneer 1 was drilled in 1990 by Shell Development Australia Pty Ltd to test the marine and fluvio-deltaic sandstones of the Middle Jurassic Petrel and lower Swan Formation in a dip and fault closed structure. This structure is located on the downthrown side of the Basin Margin Fault. The well was plugged and abandoned at a depth of 3,574 m having encountered residual oil in the Vulcan (‘Swan’) Formation and Triassic section. Petrophysical evaluation indicated hydrocarbon saturation of 0-30% for those intervals, but no net hydrocarbon zones were intersected (Table 7). Basic and interpretative well completion reports together with other well information were made available for both Prudhoe 1 and Buccaneer 1 wells.

Twelve (12) km west of the WA-332-P permit area, Echuca Shoals 1 was drilled by Woodside Offshore Petroleum Pty Ltd in 1984 (Table 7) and reported a small gas discovery in two separate reservoirs of Late Jurassic (Tithonian) to Early Cretaceous (Berriasian) in age. This well tested a large Permo-Triassic block with minor Jurassic and Lower Cretaceous drape closure, reaching a total depth of 4,365 m. The RFT data suggests a likely gas/water contact for the upper sands at 3,356 m, implying a 25 m gross gas column with 17.5m of net pay, averaging 12% porosity. The lower reservoir has 23.7m of net pay averaging 15% porosity, with gas-down-to a depth of 3,656.5 m. Basic and interpretative well completion reports and logs from this well were made available for this study.

The Heywood-1 well is located 23 km north of the WA-332-P and WA-333-P permits (Figure 3). This well was drilled in 1974 by BOC of Australia Ltd to test a Permo-Triassic/ Middle Jurassic aged horst block towards the northern margin of the Browse Basin, and reached a total depth of 4,572 m (Table 7). The well was plugged and abandoned as a dry hole with high gas readings and minor oil shows in low permeability sandstones of Jurassic and Lower Cretaceous age.

The Cornea oil and gas field is located to the northeast of the WA-333-P permit area. The Cornea 1 exploration well was drilled in 1996-1997 by Shell Development (Australia) Pty Ltd and was plugged and abandoned as an oil discovery well. The well tested Albian marine sandstones exhibiting a DHI within a basement drape closure on the Yampi Shelf and intersected a 22m oil column. The FMT Sample results for this well are presented in Table 8.

The *M. australis* sandstones of the Echuca Shoals Formation were not encountered in the Cornea well, supporting the pinchout play for the nearby Braveheart prospect. The Cornea South 2 well, located to the south of Cornea 1, flowed at a rate of 14.4 bbl/d liquids (50%) and 0.3 MMscf/d gas.

North of the Cornea Field, the Londonderry 1 well was drilled in 1973 by BOC of Australia Ltd to test a potential stratigraphic trap on the eastern margin of the Browse Basin. The well reached a total depth of 1,145 m and no significant hydrocarbon indications were encountered. The well completion report and logs were made available for this study.

Two non-commercial discoveries are located to the south of the WA-332-P and WA-333-P permits, (Figure 3) namely Caspar 1A and Gwydion 1.

Caspar 1A was a wild cat well drilled by BHP Petroleum in 1998. The well reached a total depth of 1,099 m and was plugged and abandoned as a non-commercial discovery. The well tested a drape closure over basement with an upside stratigraphic pinchout of the Hauterivian aged Middle Echuca Shoals Formation. A 5m gas column was intersected in the primary target formation in very poor reservoir quality argillaceous and glauconitic sandstones, with a residual oil column interpreted to be present below this gas. These sandstones were interbedded with siltstone and shale, and formed a barrier between two sands of very good reservoir quality (30% porosity with a net to gross of 100%), the upper of which was identified as *M. australis*. These good quality reservoir sands were found to be water wet. It is believed the residual oil column represents a previous accumulation which was flushed by the late gas charge.

Gwydion 1 was drilled in 1995 by BHP to test the Gwydion stacked amplitude anomaly, contained within an oval shaped basement drape feature with a relatively small four way closure. Three gas bearing zones and one oil (30.2° API) and gas bearing zone were intersected in Barremian to Albian aged glauconitic sandstones, of which the deepest was identified as the *M. australis* reservoir targeted in the Braveheart prospect (Spry and Ward, 1997). The final depth was 876m and the well was plugged and abandoned as an uneconomic oil and gas discovery. The petrophysical analysis is presented in Table 9.

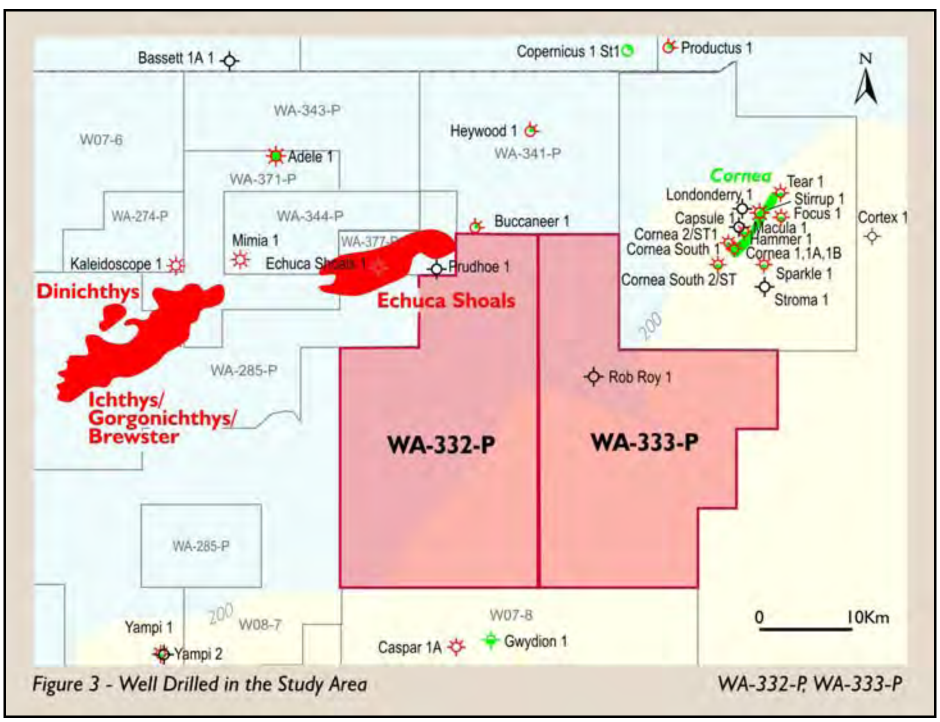

Figure 3 - Well Drilled in the Study Area

Well Name	Year	Operator	TD (m MD)	Structure tested	Net pay (m)	Reservoir porosity (%)	Hydrocarbon
Wells in WA-333-P							
Rob Roy 1	1972	BOC of Australia Ltd	2,286	Asymmetric graben			No indications
Wells on the edge of WA-332-P							
Prudhoe 1 & ST1	1974	BOC of Australia Ltd	3,322	Fault-bounded structure			No indications
Bucanneer 1	1990	Shell	3,574	Dip and fault closed structure			Residual oil (0-30% oil saturation)
Wells adjacent to WA-332-P and WA-333-P							
Echuca Shoals 1	1984	Woodside	4,365	Large Permo-Triassic block	17.5	12	Small gas discovery in two reservoirs
					23.7	15	
Heywood 1	1974	BOC of Australia Ltd	4,572	Permo-Triassic/ Middle Jurassic horst block			High gas reading and minor oil shows
Cornea 1	1996 - 1997	Shell	831	Albian drape play	22 m oil	Very poor quality of reservoir	Oil and gas fields
Londonderry 1	1973	BOC of Australia Ltd	1,145	A potential stratigraphic trap			No indications
Caspar 1A	1998	BHP	1,099	Drape closure over the basement and an upside stratigraphic pinchout	5 m gas	Very poor quality of the reservoir bearing the gas column, but very good quality for *M. australis*	Un-commercial gas discovery
Gwydion 1	1995	BHP	876	An oval shaped feature	See Table 6	See Table 6	Oil and gas discovery

Table 7 - Key wells for the study area

Depth (m)	Sample Results
802.1	0.5L oil, 3.0L water/mud filtrate
777.1	45 ft^3 gas with oil slick
777.1	50.3 ft^3 gas with oil slick
802.5	> 1L oil

Table 8 – FMT sample results for Cornea 1 well in the Albian reservoir

Age of reservoir	Petrophysical Analysis							
	Zone	Depth Interval (m)	Av. Porosity (%)	Gross (m)	Net (m)	N/G (%)	Sw (%)	Liquid phase
Albian-Hauterivian	Zone 1	675-680	27	5	5	100	66	Gas
		680-685	25	5	3.1	61	92	? Water
	Zone 2	691-695	27	4	4	100	48	Gas
		695-700	22	5	3.9	79	100	Water
	Zone 3	718.5-723.5	26	5	5	100	72	Gas
		723.5-732	23	8.5	8.5	100	90	Water
		GOC at 809 mMD						
	Zone 4	795-809	24	14	12.6	90	61	Gas
		809-819.5	27	10.5	10.4	99	39	Oil
		Owc at 819.5 mMD						
		819.5-830	21	10.5	10.1	96	100	Water

Table 9 – Petrophysical analysis of the reservoirs penetrated by Gwydion 1 well.

3. REGIONAL GEOLOGY

The Browse Basin lies entirely offshore and covers an area of approximately 140 000 km^2. It can be divided in three major sub-basins, namely the Caswell, Barcoo and Seringapatam (Struckmeyer et al, 1998) as illustrated in Figure 4. The Browse Basin is bounded to the estate and southeast by the Prudhoe Terrace, Yampi Shelf and Leveque Shelf. The basin is flanked to the west by the Scott Plateau and is contiguous with the Rowley Sub-basin of the Roebuck Basin to the southwest, and the Ashmore Platform, Vulcan Sub-basin and Londonderry High of the Bonaparte Basin to the northeast. The WA-332-P and WA-333-P permits are located on the border of the Prudhoe Terrace and the Yampi Shelf.

3.1 Regional Structural Setting and Tectonic Evolution

The Browse Basin has a complex tectonic evolution which consists of six major phases (Struckmeyer et al, 1998). A brief description of each of these phases as follows.

3.1.1 Extension (Late Carboniferous to Early Permian)

During this first tectonic phase the development of the basin was initiated as a series of intracratonic extensional half-grabens. This extensional phase is considered to have been driven by the breakup and separation of Sibumasu from northwest Australia in the Early Permian (Metcalfe, 1990), which resulted in widespread extension throughout the North West Shelf. Structures formed during this extensional event were later reactivated, and played a critical role in controlling the distribution and nature of the sedimentary fill (Struckmeyer et al, 1998).

3.1.2 Thermal Subsidence (Late Permian to Triassic)

The sag phase of the Late Carboniferous to Early Permian rifting event described above took place during the Late Permian to the Triassic. During this time, a passive margin environment was developed, with transgressive to shallow marine conditions prevailing (Blevin et al, 1998).

3.1.3 Inversion (Late Triassic to Early Jurassic)

The Permo-Triassic sag phase was terminated by compressional reactivation in the Late Triassic to Early Jurassic (Kennard et al, 2005). This event resulted in reactivation and the partial inversion of Paleozoic half-grabens, with the formation of large scale anticlines within the hanging walls. The arcuate Buffon–Scott Reef–Brecknock Anticline Trend, which hosts the Torosa accumulation, was developed during this time.

3.1.4 Extension (Early to Middle Jurassic)

A second extensional phase during the Early to Middle Jurassic resulted in the development of widespread small scale faults and the collapse of anticlines formed during the Triassic subsidence phase. Major extensional faulting was concentrated in the northeastern part of the Caswell Sub-basin and along the adjacent outer margin of the Prudhoe Terrace. The Heywood Graben also formed during this period. During the Late Middle Jurassic continental break-up produced a major regional unconformity (Callovian Unconformity), consisting of widespread erosion and peneplanation across the North West Shelf. This event is clearly evident in seismic data, as illustrated in Figure 5.

3.1.5 Thermal Subsidence (Late Jurassic to Early Miocene)

From the Late Jurassic to Early Miocene, a second phase of thermal subsidence combined with higher sea levels created greater accommodation space, allowing for large volumes of sediment deposition. Active faulting continued in the Heywood Graben where thick sequences of marine mudstones were deposited (Kennard et al, 2005). A second marine sequence was deposited during the Early Cretaceous when marine conditions were established throughout the Browse Basin. Throughout the Turonian to Tertiary, a major progradational cycle was developed, with the continental shelf edge migrating westwards as thick sequences of carbonates were deposited on the rapidly subsiding western shelf margin.

3.1.6 Inversion (Middle to Late Miocene)

Compression took place during the Middle to Late Miocene as a result of the convergence of the Australia-India and Eurasia Plates. Although relatively minor, this compression resulted in fault reactivation and structural shape changes, which in many cases forced leakage and onward migration of hydrocarbons.

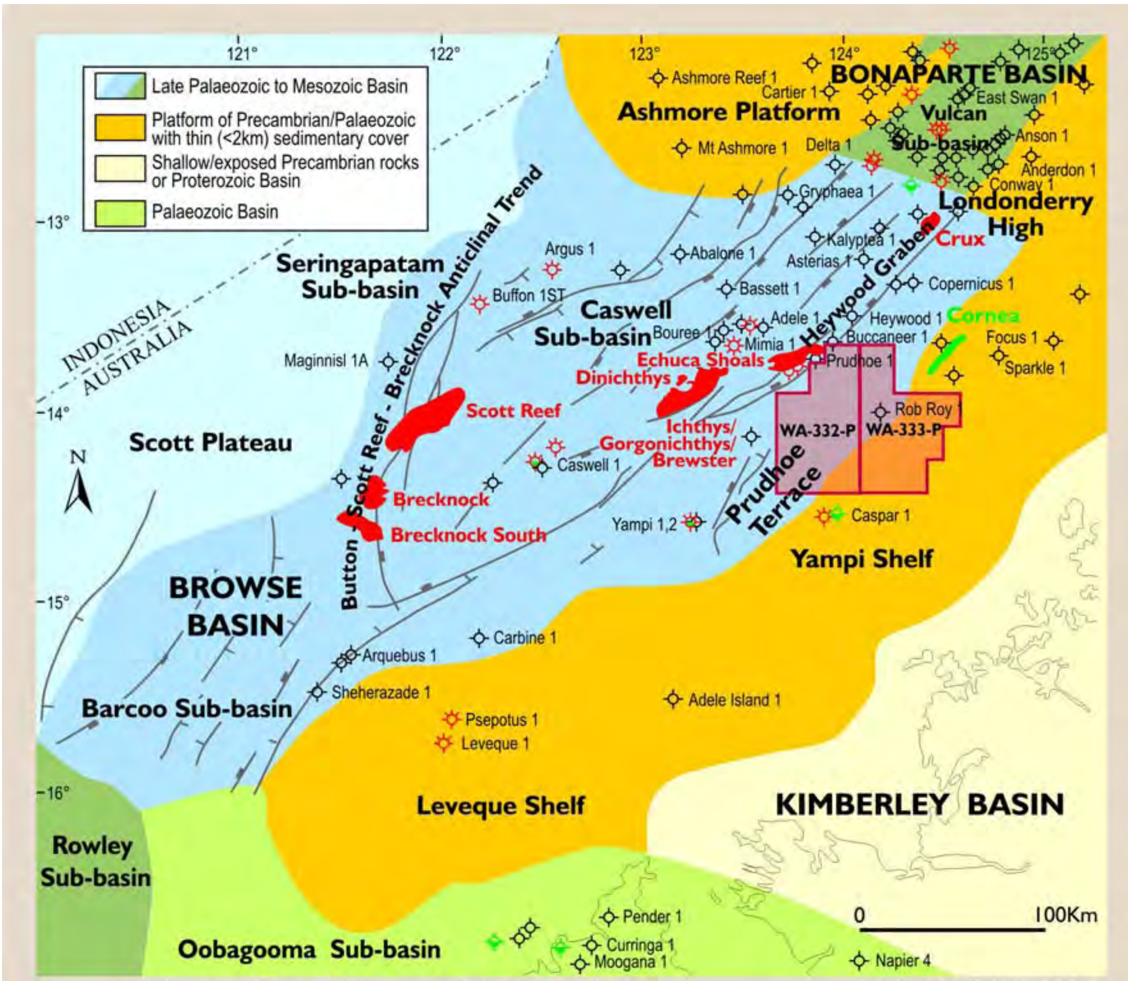

Figure 4 - Schematic Tectonic Elements of the Browse Basin *WA-332-P, WA-333-P*

Figure 4 - Schematic tectonic elements of the Browse Basin

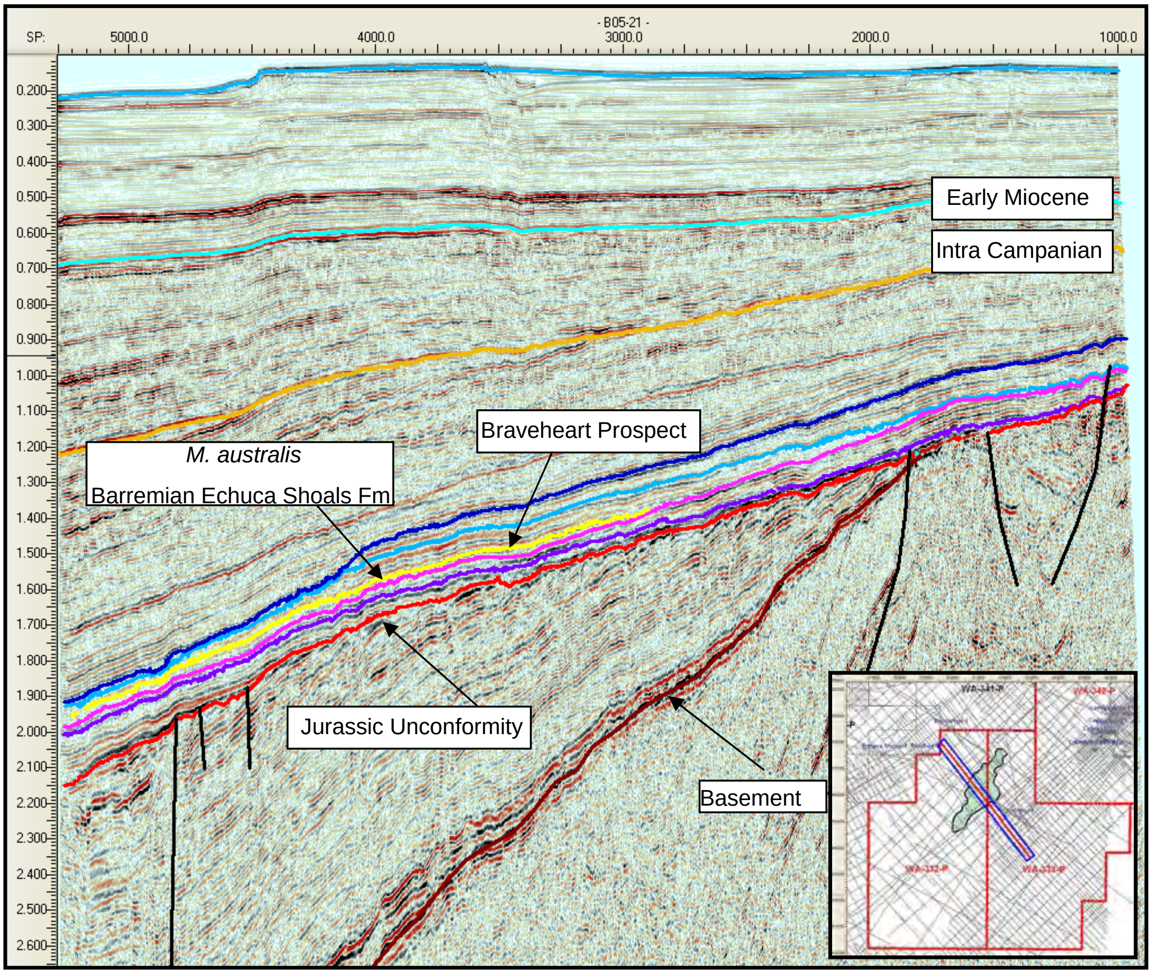

Figure 5 - Seismic interpretation of the B05-21 line depicting the main structural features and the Braveheart Prospect

3.1.7 Stratigraphy

No formal lithology has been established for the Browse Basin and the nomenclature from the Vulcan Basin was adopted by Blevin et al (1998 a) and Struckmeyer et al (1998).

The Browse Basin is a Palaeozoic to Cenozoic depocentre that consists of two series of sedimentary rocks separated by a major Jurassic unconformity. The earlier series, deposited during the two rifting phases (Carboniferous-Permian and Early to Middle Jurassic) consist predominately of fluvio-deltaic and shallow marine clastics. The younger series is predominantly marine and is affected by a limited numbers of faults.

A summary of the lithology and depositional the environment is provided below and is exemplified by Figure 6.

The Carboniferous section is dominated by fluvio-deltaic sediments, while the limestones and shales of Early Permian were deposited in a marine environment. The Late Permian section consists of sandstones grading into shales and limestones.

The oldest Triassic rocks intersected in the Browse Basin are marine claystones, siltstones and volcaniclastic sediments deposited during a regional Early Triassic marine transgression. The overlying Triassic rocks include fluvial and marginal to shallow marine sandstones, limestones and shales.

The Early–Middle Jurassic sediments (Plover Formation) are comprised of sandstones, mudstones and coals that accumulated in deltaic and coastal-plain settings with minor marine influences. Braided fluvial, barrier bar, channel and marine shelf sandstones provide good reservoirs, while overbank, interdistributary and lower delta plain carbonaceous siltstones and shales are important sources of gas and in some instances, light oil. Late Jurassic interbedded marine sandstones and shales of the Vulcan Formation onlap and drape the pre-Callovian structures, providing a thin, regional seal and a potential source rock across much of the basin.

An overall transgressive cycle began in the Early Cretaceous, this peaked in the mid-Turonian, and continued until the Aptian, when open marine condition was established throughout the entire basin. Thick marine claystones deposited during this period (Echuca Shoals and Jamieson formations) provide a regional seal and contain potential source rocks, with particularly high total organic carbon (TOC) values recorded at the maximum flooding surfaces of several Early Cretaceous transgressive cycles. Good reservoir quality sandstones are believed to have been deposited during the Barremian when a third cycle lowstand event occurred. The sandstones of slope associated submarine fans deposited during this cycle, classified as the *M. australis* biozone, represent the main reservoir in the Braveheart Prospect (Figure 7).

The Turonian–Cenozoic section represents a major progradational (regressive) cycle in which the shelf edge migrated northwestwards to the outer limits of the Buffon–Scott Reef–Brecknock Anticline Trend. The development of submarine canyons on the Yampi Shelf and deposition of turbidite mounds within the central Caswell Sub-basin occurred during the Middle to Late Campanian.

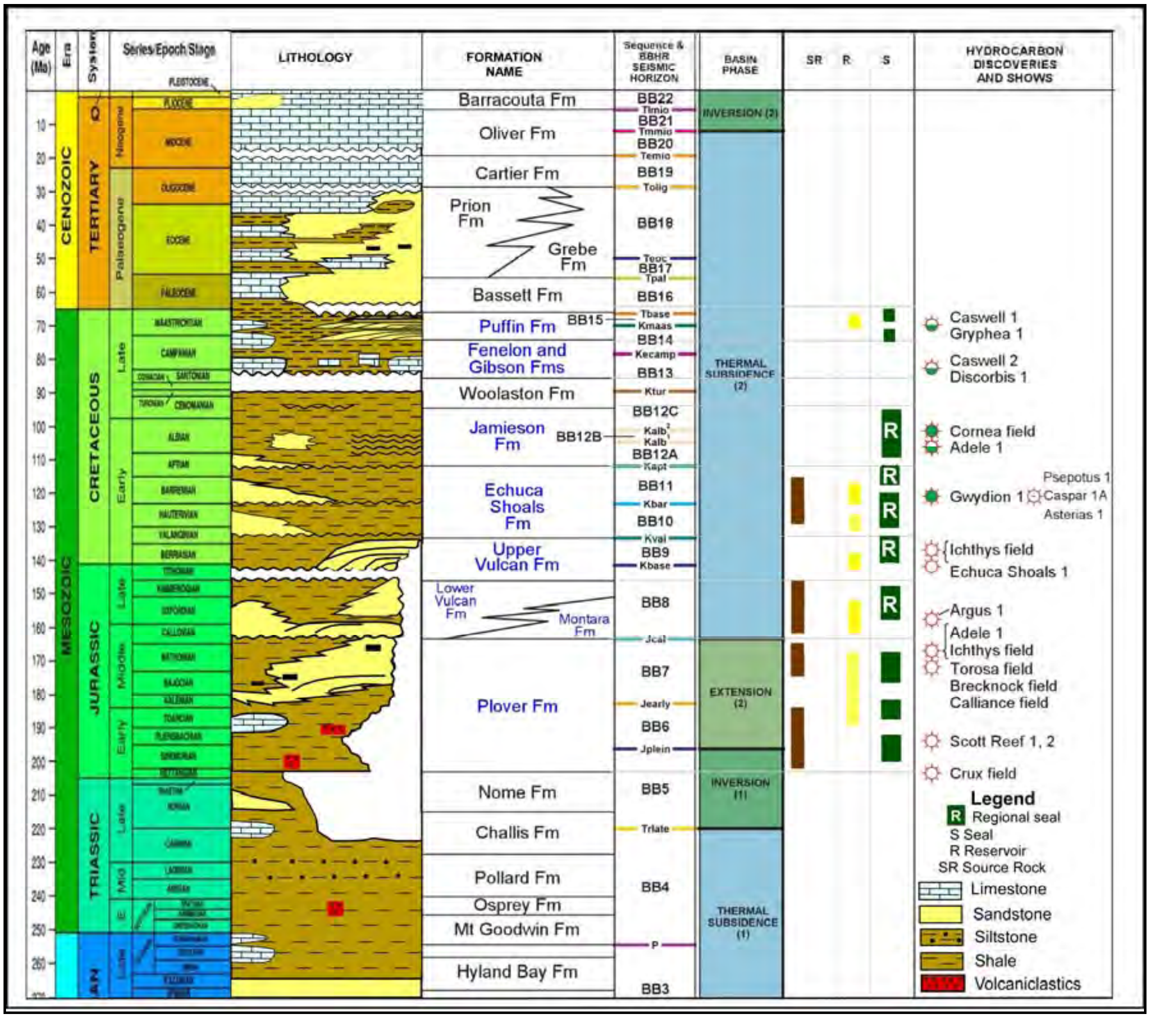

Figure 6 - Tectonostratigraphic Summary and Petroleum system of the Browse Basin

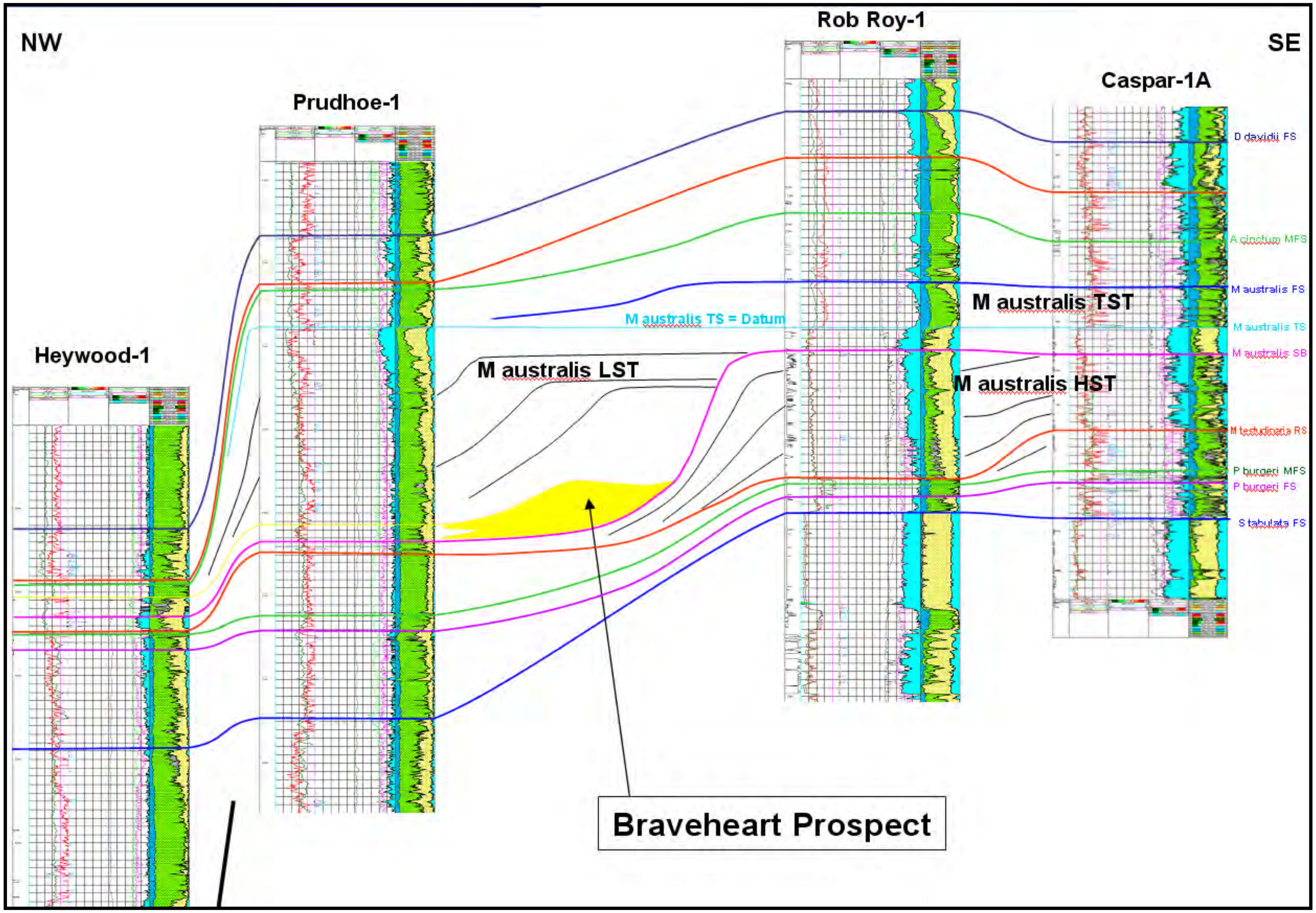

Figure 7 - Sequence stratigraphic well correlation with the interpretation of the Braveheart Prospect submarine fan

4. PETROLEUM SYSTEM ANALYSIS

4.1 Source Rocks and Maturity

The presence of a mature source rock and working petroleum system in the Browse Basin is proven by the fields and small discoveries located in the basin. Both oil prone and gas prone source rocks are interpreted, with the most oil-prone source potential associated with the transgressive marine shale sequences of the Late Jurassic–Early Cretaceous (Vulcan Formation and Echuca Shoals Formation), and the more gas-prone source associated with the fluvo-deltaic shale of the Early-Middle Jurassic (Plover Formation).

The Early-Middle Jurassic Plover Formation is pervasive throughout the basin and consists of lower coastal plain shaly coals and pro-delta shales, with TOC values of between 1.5 and 3%, and HI values ranging from 150 to 250. These shales are composed almost entirely of terrestrial organic matter, the majority of which is humic (rather than sapropelic) kerogen and therefore are predominantly gas-prone with dry gas and wet gas/condensate produced, dependant on maturity. The Plover Formation is believed to have sourced the hydrocarbons reservoired in the Scott Reef, Brecknock, and Ichthys fields, and the Crux and Argus discoveries.

It should be noted that it is also probable that light oil has been expelled from the Plover Formation source rocks in the Browse Basin, as has taken place further north in the Bonaparte Basin. However the depth and pressure at which known accumulations of these hydrocarbons are reservoired is such that the hydrocarbons are in the condensate phase. It is possible that yet to be discovered accumulations could develop an oil rim were they to be reservoired at shallower depths.

The Late Jurassic Vulcan Formation and Early Cretaceous Echuca Shoals Formation are also potential source rocks within the Browse Basin, and due to their deposition in a marine setting and lower maturity, are considered to be more oil-prone than the source rocks of the Plover Formation. The Late Jurassic section is generally thin throughout the Browse Basin but local thickening occurs on the Leveque Shelf and Prudhoe Terrace. In those areas the section is dominated by deltaic facies with poorer quality terrigenous organic matter. The excellent source rock quality of in this sequence in the Vulcan Graben to the north is not present in the Browse Basin, as no major Oxfordian/Tithonian rifting event took place and therefore the restricted conditions necessary were not developed.

Thick sections of Early Cretaceous Echuca Shoals Formation marine sediments occur within the Caswell Sub basin and contain mixed marine and terrestrial organic matter with moderate to good source potential. The available pyrolysis data suggests that these sediments have good liquids potential within the Caswell Sub-basin (HI=150–350 mg hydrocarbons/g Rock). Recent hydrocarbon generation and expulsion studies of the Early Cretaceous source confirm the existence of potential source rocks that are early mature for oil generation and expulsion.

Effective oil charge from parts of the Echuca Shoals Formation and the Vulcan Formation is confirmed by geochemical analysis of the Cornea, Gwydion 1 and Caswell 2 accumulations.

With this summary in mind, charge to the Braveheart prospect is not considered a high risk. Maturity and migration modeling of the Caswell Sub-basin suggests the Plover Formation is mature present day for gas expulsion, while the Vulcan Formation exhibits present day maturity for gas expulsion from the deepest parts of the sub-basin and oil expulsion from the shallower parts of the basin. The Echuca Shoals Formation, considered to be the most oil-prone of the source rocks in the Browse Basin, is interpreted to be early mature for oil expulsion. Lateral migration of hydrocarbons from the Late Jurassic to Early Cretaceous and vertical and lateral migration of hydrocarbons from the Early to Middle Jurassic is likely to have taken place and therefore both an oil and/or gas accumulation are feasible. However, the volume of oil expelled from the Late Jurasssic to Early Cretaceous is considered to be relatively small (Kennard et al, 2005), and there is also a high risk of accumulated oil being flushed from the reservoir by a late gas charge from the Plover Formation, as has taken place at Caspar 1A and possibly Echuca Shoals 1.

4.2 Reservoir and Trap

The main reservoirs in the Caswell Sub-basin (Figure 6) are present in the fluvio-deltaic Plover Formation (Early–Middle Jurassic) and the submarine fans and “ponded” turbidite mounds of Berriasian sandstones (Brewster Sandstone of Upper Vulcan Formation). Also the Barremian *M. australis* sandstones of Echuca Shoals Formation and the Puffin Sandstones (Campanian – Maastrichtian). Porosities of the *M.australis* sandstone reservoir in the nearby Gwydion 1 well are in the order of 24-27% (Spry and Ward, 1997), with a net to gross of almost 100%.

The primary structural traps in the basin consist of Late Triassic faulted anticlines and Jurassic horst/tilted fault blocks associated with drape anticlines. Cretaceous submarine canyon fill, basin floor fans and “ponded” turbiditic stratigraphic traps are also expected in this area.

The Braveheart prospect is a stratigraphic play with reservoir sandstones of the *M. australis* Echuca Shoals Formation having been interpreted.

4.3 Seals

The thick marine claystones of the Echuca Shoals Formation and the regional Albian aged Jamieson Formation are expected to form the seal for the Braveheart Prospect. However, seal is considered a critical risk to the prospect, as the primary reason for failure of the analogous stratigraphic target in the Caspar 1A well (which relied on an updip pinchout of the target reservoir) was was due to the lack of an effective base seal.

Additional seal may be provided by the claystones of the Vulcan Formation (Figure 6). Potential intraformational sealing shales also occur within the Early–Middle Jurassic Plover Formation, while Late Cretaceous claystones of the Puffin Formation provide potential seals for Campanian–Maastrichtian ponded turbidites and unconfined fans.

5. GEOPHYSICAL AND SEISMIC INTERPRETATION REVIEW

WA-332-P and WA-333-P permits are covered by different 2D surveys. As can be seen in Figure 8 a denser seismic coverage exists over the WA-333-P permit. The Braveheart Prospect is intersected by a reasonable number of seismic lines trending northwest – southeast and northeast – southwest which are of good quality.

The seismic interpretation of the Braveheart Prospect was supplied by the Exoil Ltd and consists of a stratigraphic trap related to the pinchout of *M. australis* Echuca Shoals reservoir against the *M. australis* sequence boundary (Figure 9). The depositional model and geometry of the reservoir involved in this prospect is presented in the Figure 7. The model used in the interpretation is a submarine fan play deposited at the base of the slope. The main uncertainty related to the depositional model is the size of the slope. Flattening on the seismic lines indicates a possible slope of about 40 metres (Figure 11). However a good reservoir is expected in this area and is probably similar to the reservoir penetrated by Caspar 1A well drilled 13.6km north to WA-332-P permit area. The Braveheart Prospect is highlighted by a high amplitude seismic signature (Figure 12), this high amplitude area corresponds to the thickest part of the interpreted isopach, (Figure 13).

A large amount of AVO analysis was performed on the seismic data, a representative seismic line is shown in Figure 15. In general a positive AVO response indicating hydrocarbon content was observed. Particularly encouraging was that the AVO response terminated at the same two-way-time at both the top and the bottom of the sedimentary unit suggesting a common hydrocarbon-water contact.

Also forward modeling that resulted in the prediction of fluid phase and reservoir parameters was completed following calibration to the regional wells. This was performed using “Delivery” an open sourced, model based Bayesian seismic inversion software package. The results generally give support to reservoir quality rocks and also indicate hydrocarbons could be found within the Braveheart Prospect, (Figure 16 and Figure 17).

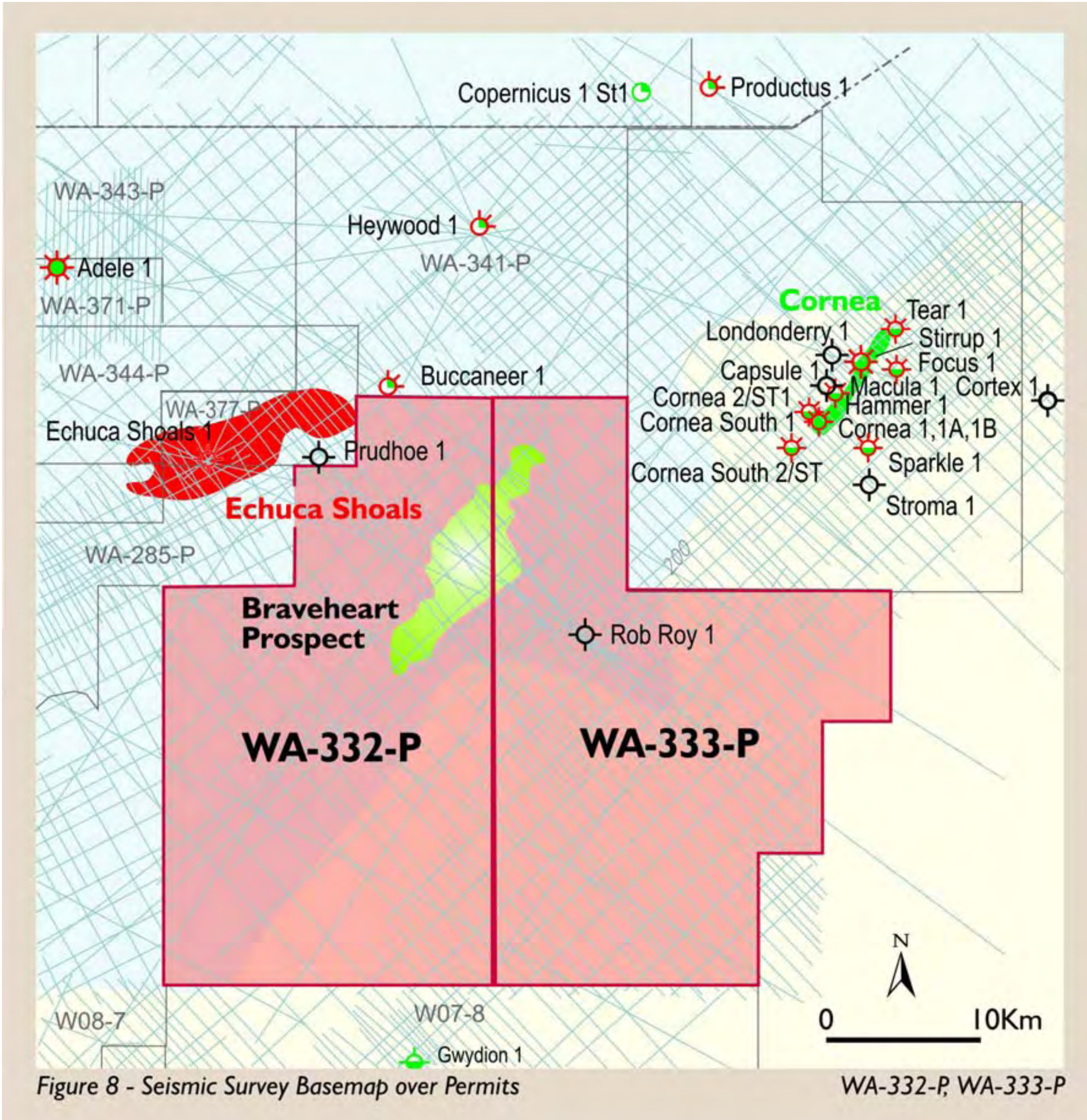

Figure 8 - Seismic survey basemap over the WA-332-P and WA-333-P permits.

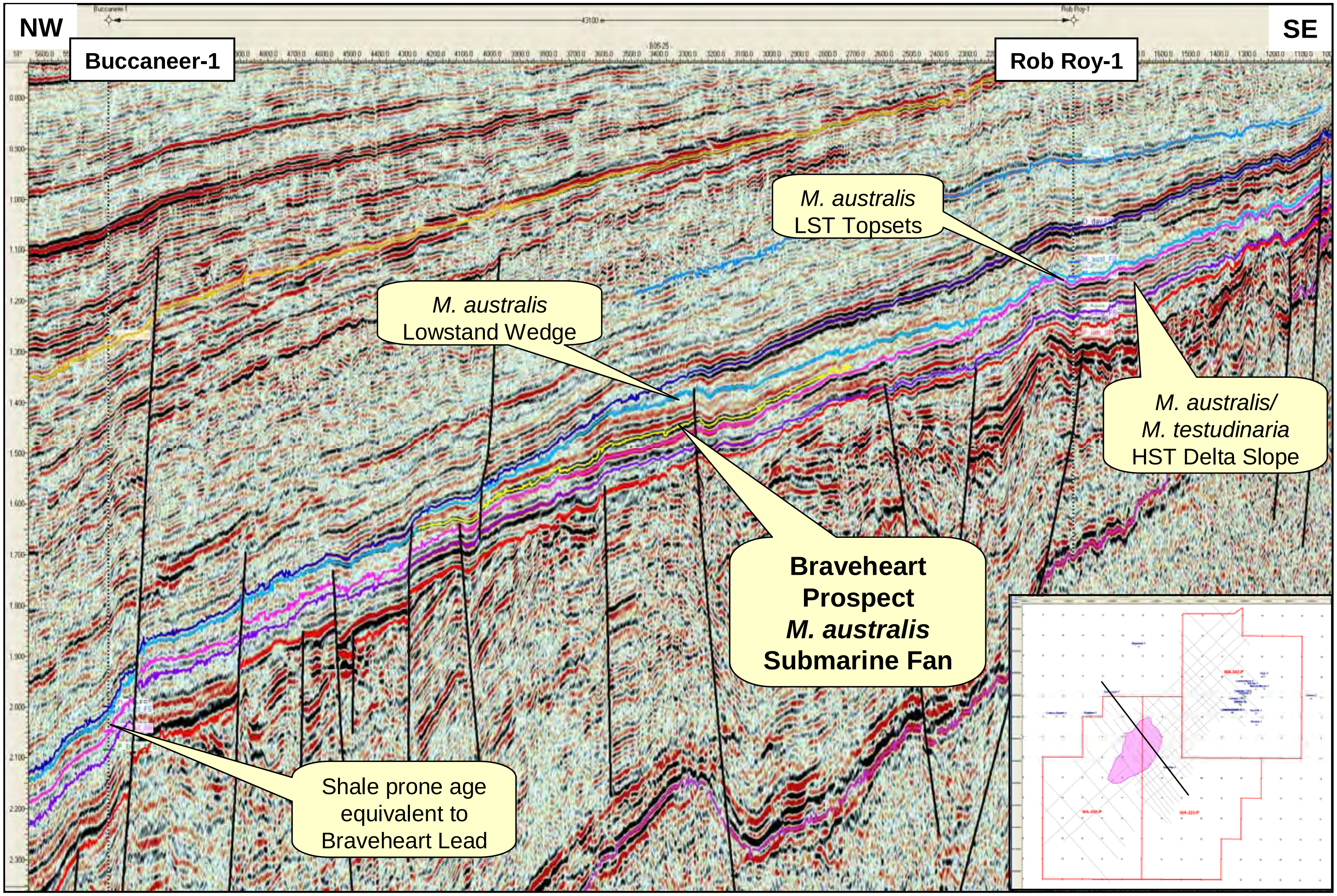

Figure 9 - Seismic line B05-21 depicting the Braveheart Prospect

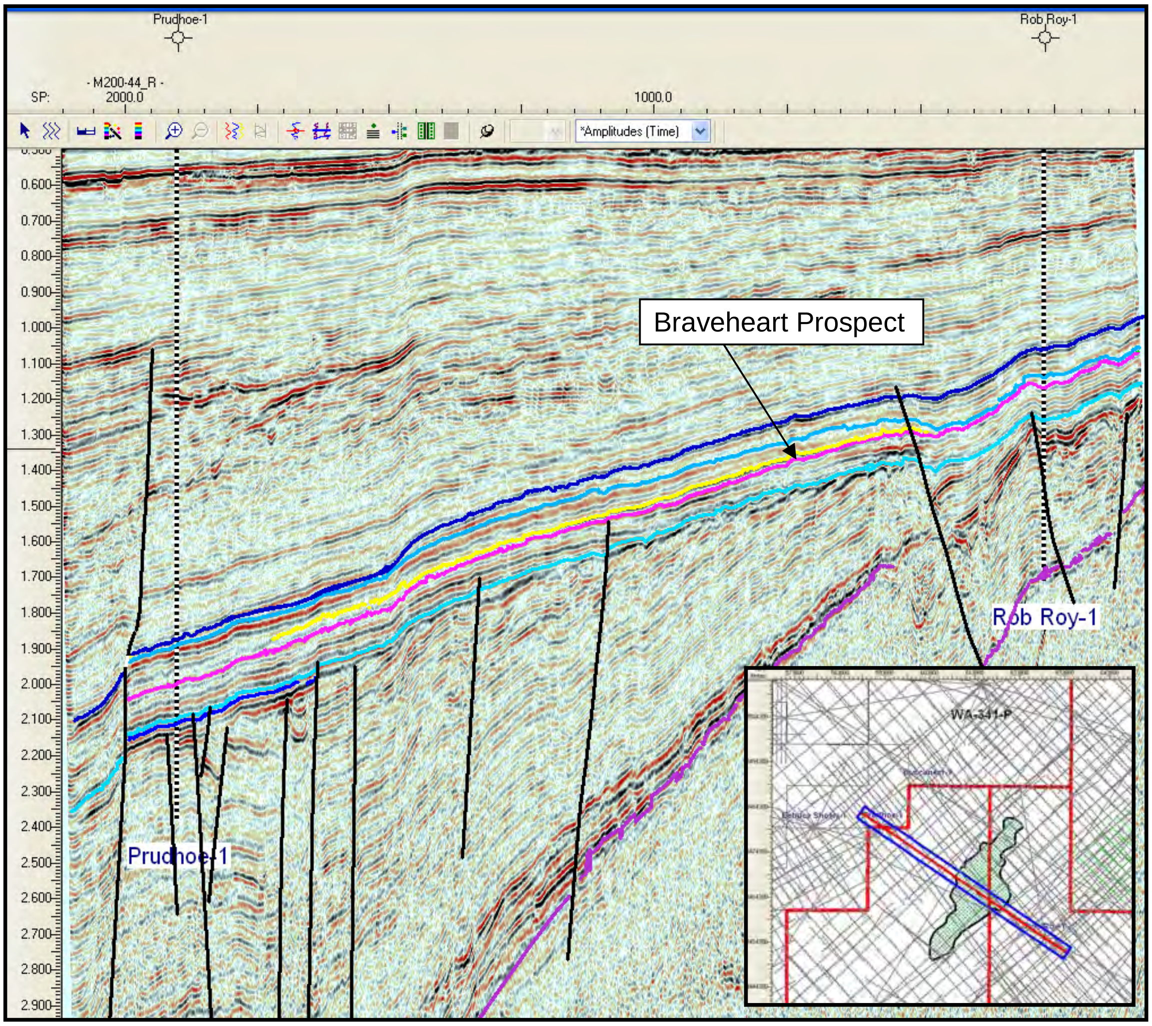

Figure 10 - Seismic line M 200_44_R between Prudhoe-1 and Rob Roy-1 wells

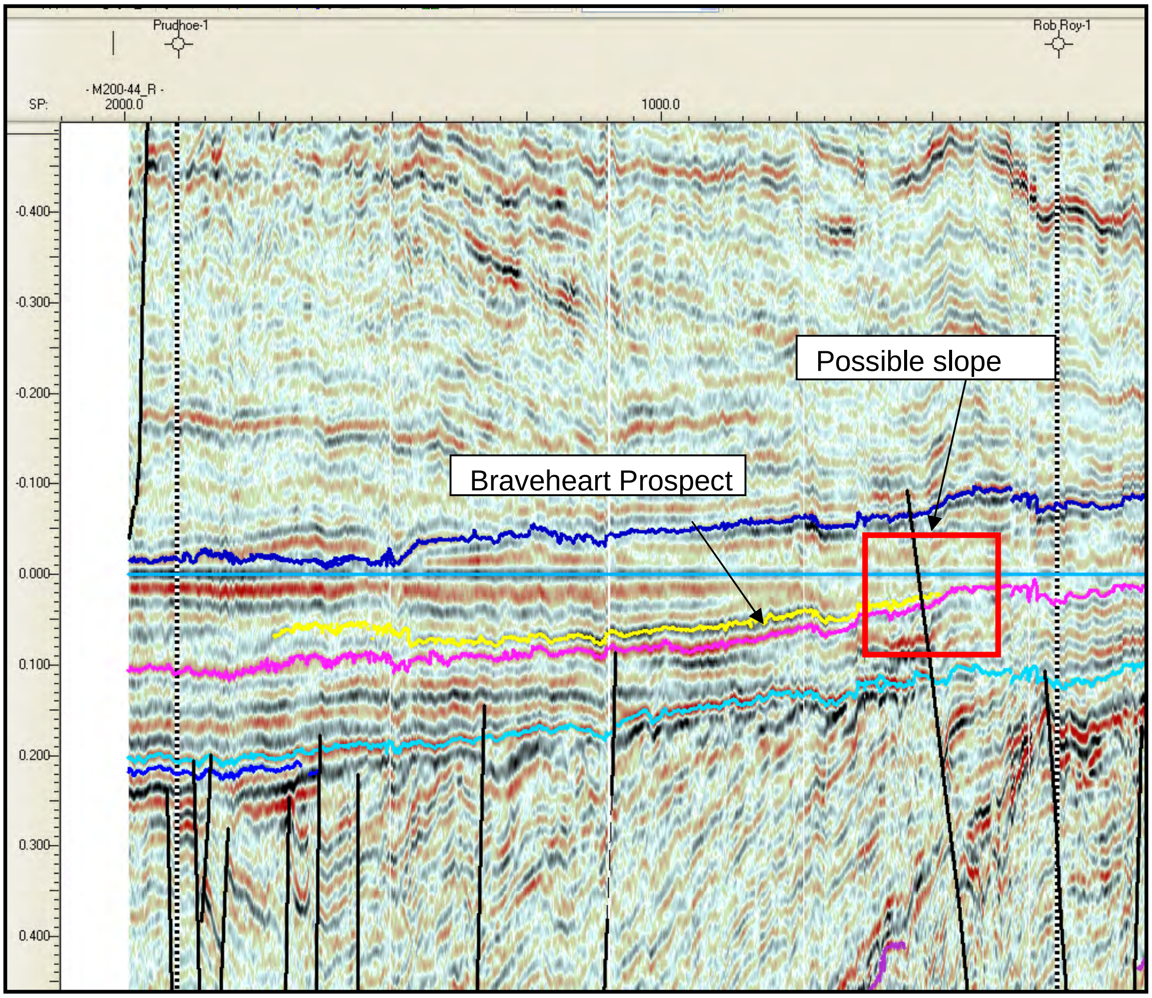

Figure 11 - Flattened interpretation of the seismic line M 200_44_R.

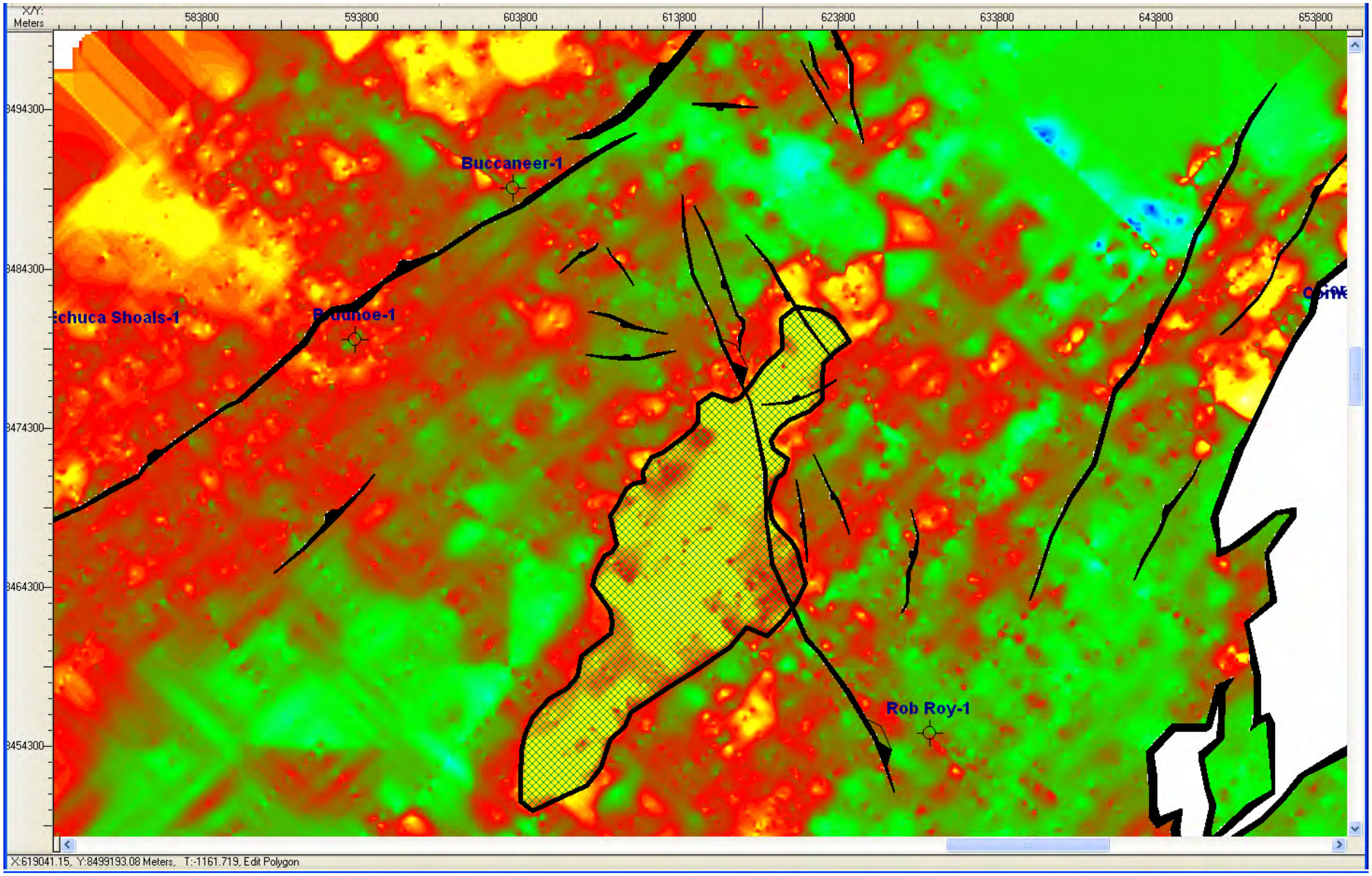

Figure 12 - Top M. australis horizon Seismic Amplitude Map

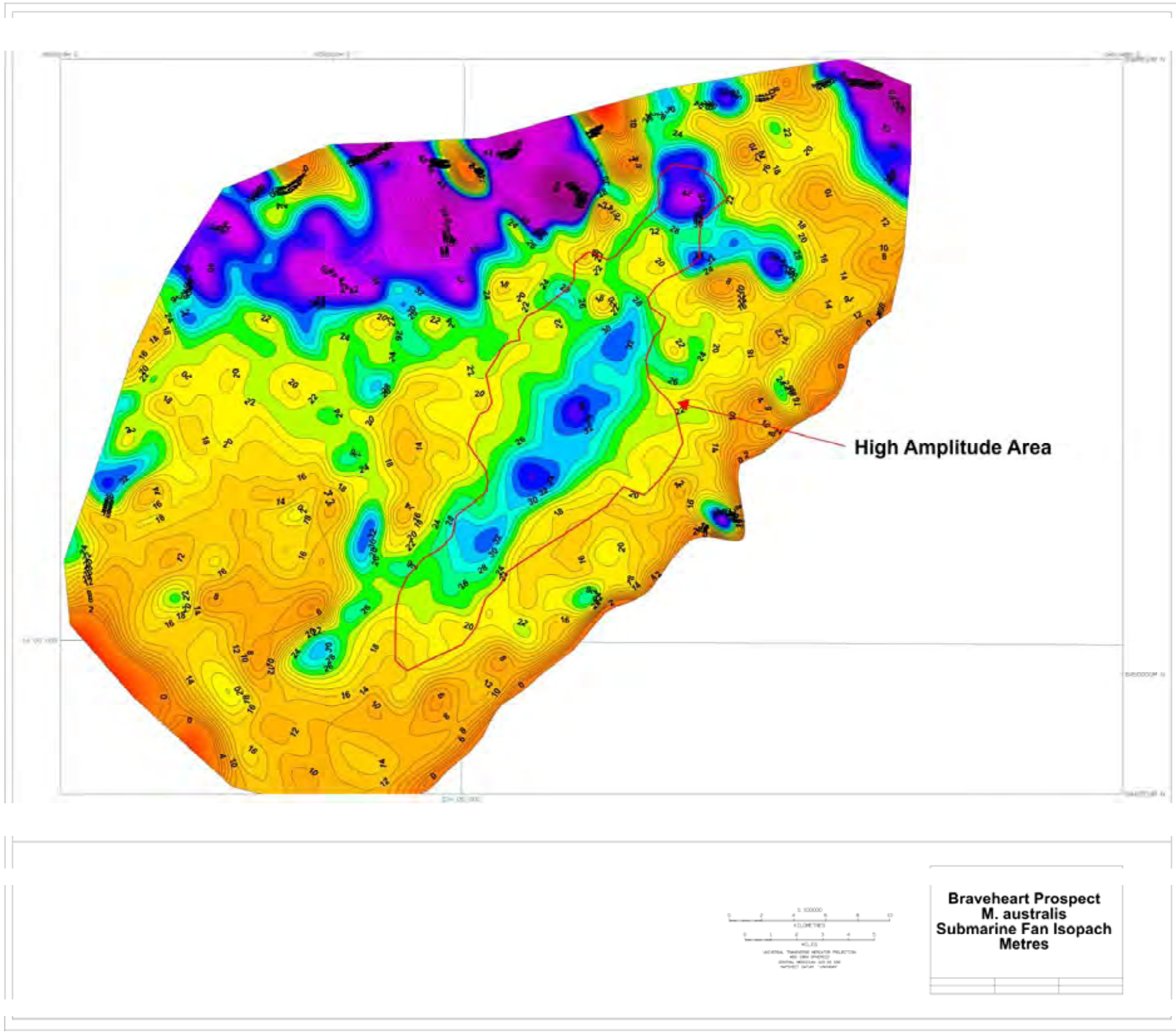

Figure 13 - Braveheart : M. australis Isopach Map

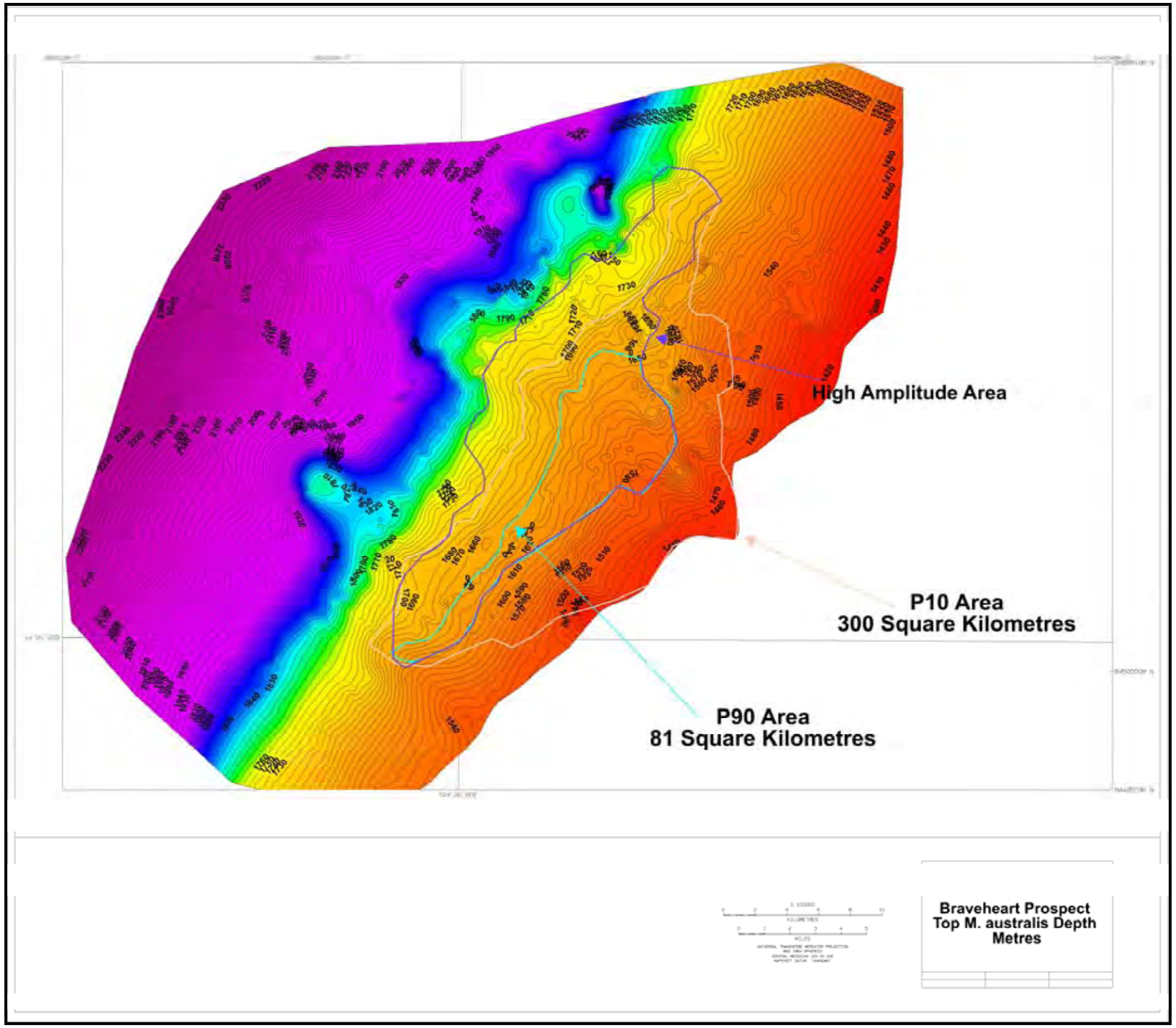

Figure 14 - Top M. australis Depth Map

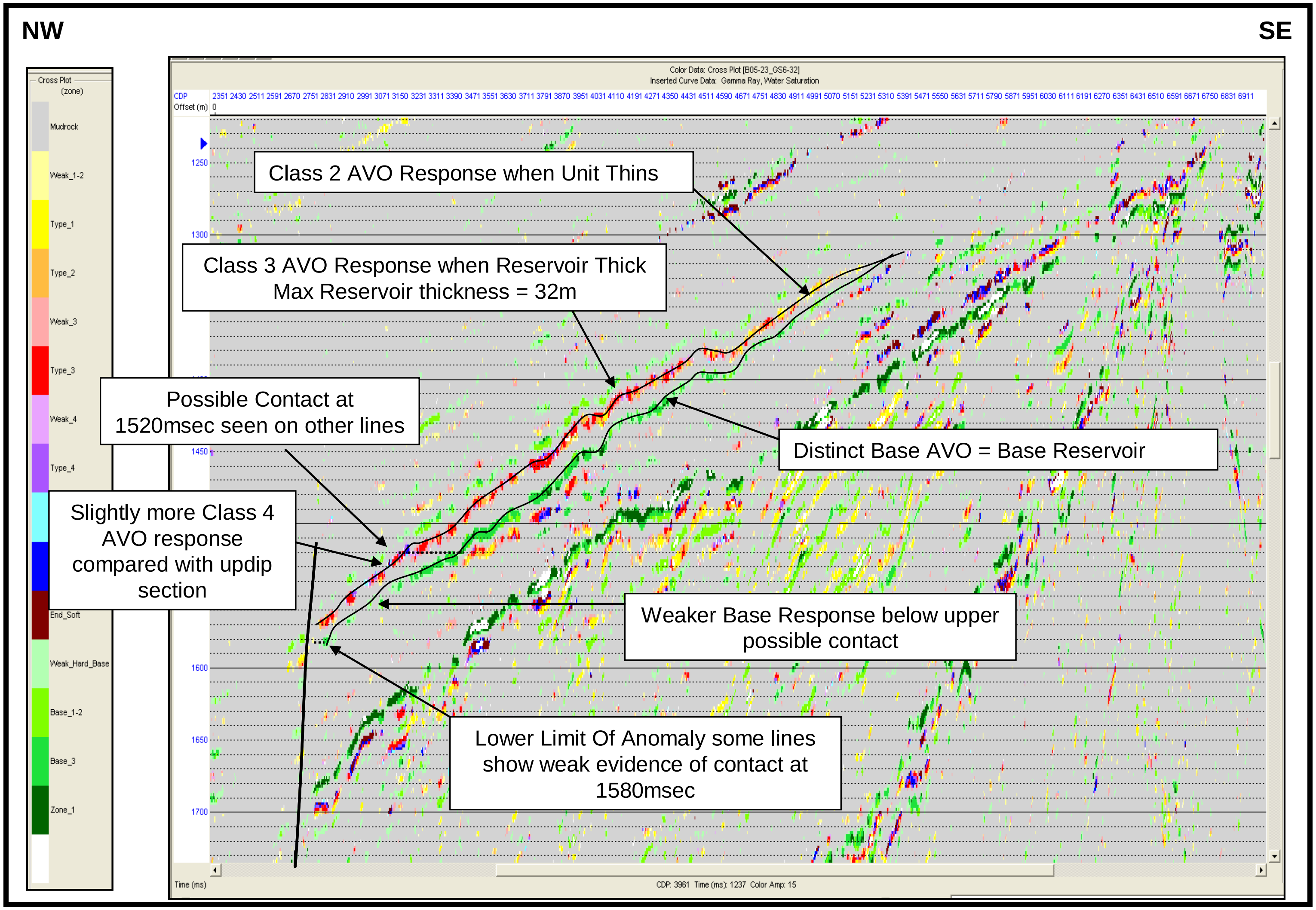

Figure 15 - AVO anomalies based in the interpretation of seismic line B05-23

Delivery Bayesian Stochastic Inversion of B05-25 : CDP 4995: – All Realisations

Layer Properties for the Braveheart Sand

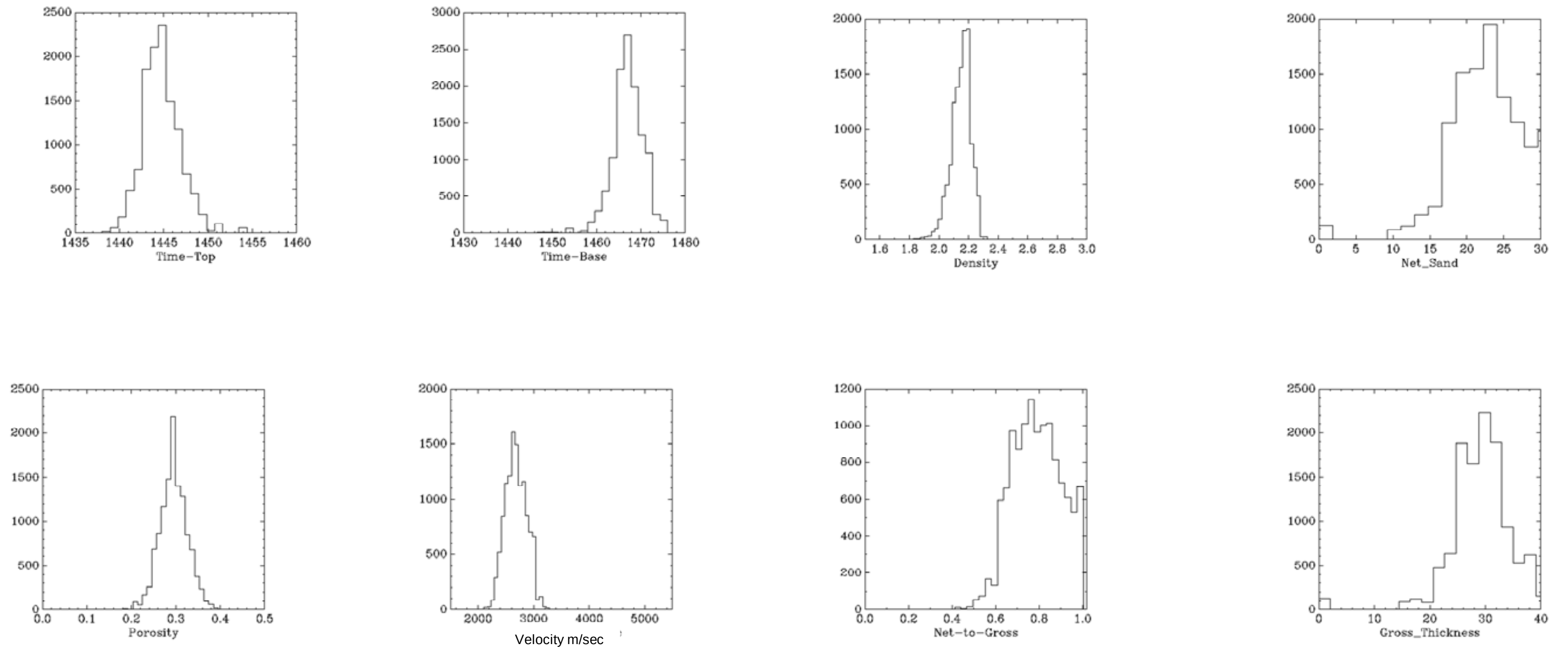

Figure 16 - Predicted Braveheart Reservoir Properties from "Delivery"

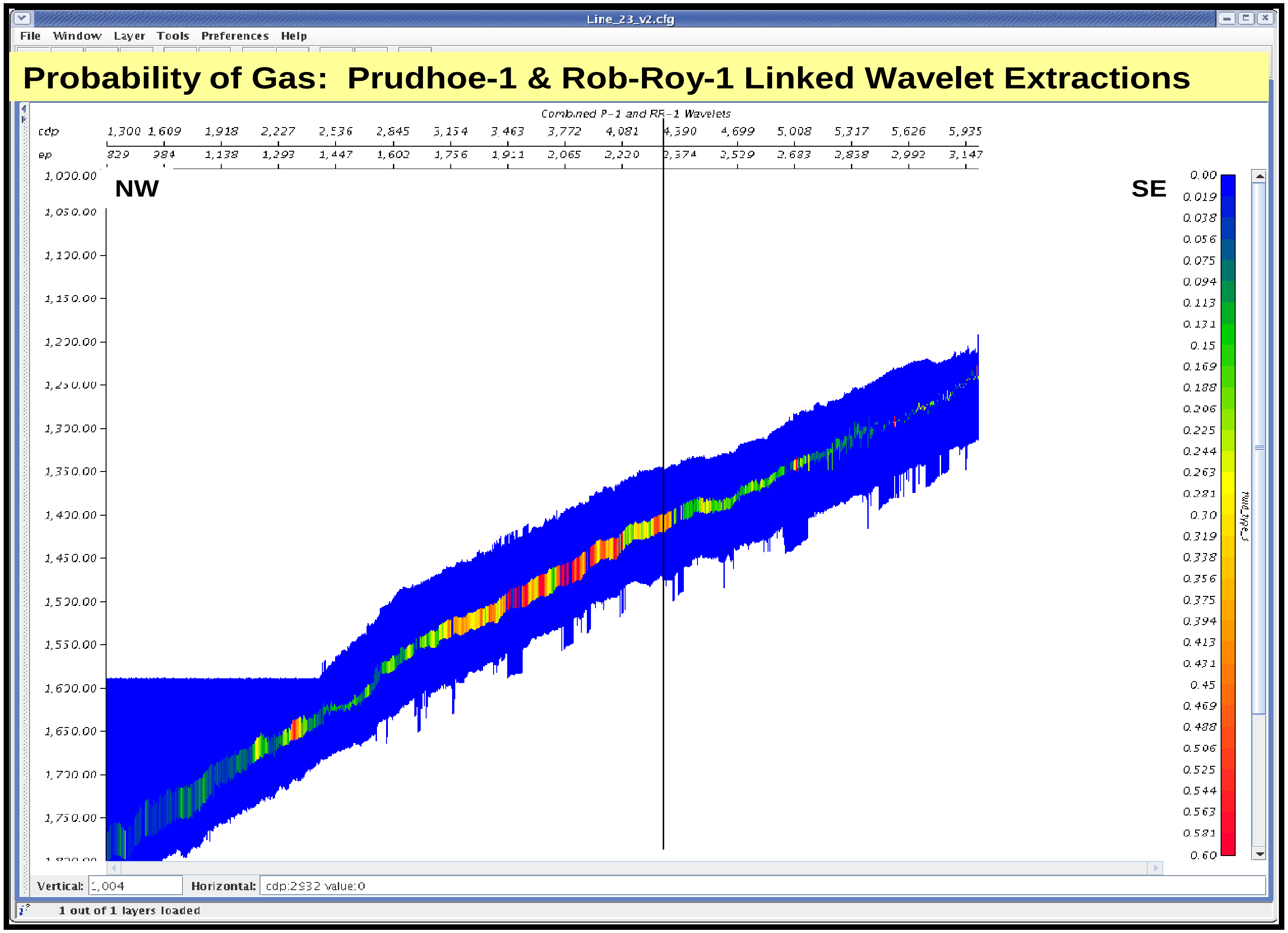

Figure 17 - Probability of Gas with the Braveheart reservoir from "Delivery"

6. PROBABILISTIC PROSPECTIVE RESOURCES

6.1 Gross Rock Volume (GRV)

The GRV was calculated by the Area/Thickness/Shape factor method. The area of closure P10-P50-P90 range used in volumetric calculations within this report was calculated from mapping.

6.2 Net to gross

High net to gross values were reported by different wells for *M. australis* Echuca Shoals reservoir. A net to gross close to 100% was reported by the Caspar 1A well, whilst 94% for the Gwydion 1 well and 75% was reported for Asterias 1 well (Figure 18). A range of 30-60-100 was used for the evaluation of Braveheart Prospect.

6.3 Porosity and Permeability

An average porosity of 30% characterizes *M. australis* Echuca Shoals sandstones in Caspar 1A well. In general the MDT interpretation indicates a high permeability for this reservoir.

The porosity P10-P50-P90 range used in volumetric calculations within this report was: 18%-22%-33%.

6.4 Water Saturation (Sw)

No information about water saturation of the reservoirs is available for this area. The estimated P10-P50-P90 range used in volumetric calculations within this report was 20-30-50%

6.5 Gas Recovery Factor (RF)

The P10-P50-P90 range of recovery factor of 60-70-85% was used.

6.6 Oil Formation Volume Factor (FVF)

The P10-P50-P90 FVF range used in volumetric calculations within this report is 1.1 - 1.3 - 1.4.

6.7 Gas Formation Volume Factor (1/Bg)

The P10-P50-P90 gas expansion factor was used in volumetric calculations within this report is 160-200-240.

6.8 Condensate/Gas Ratio

The P10-P50-P90 condensate/gas ratio was 30-50-80 bbl/mmcf

6.9 Gas/Oil Ratio

The P10-P50-P90 gas/oil ratio was 100-200-300 cf/bbl.

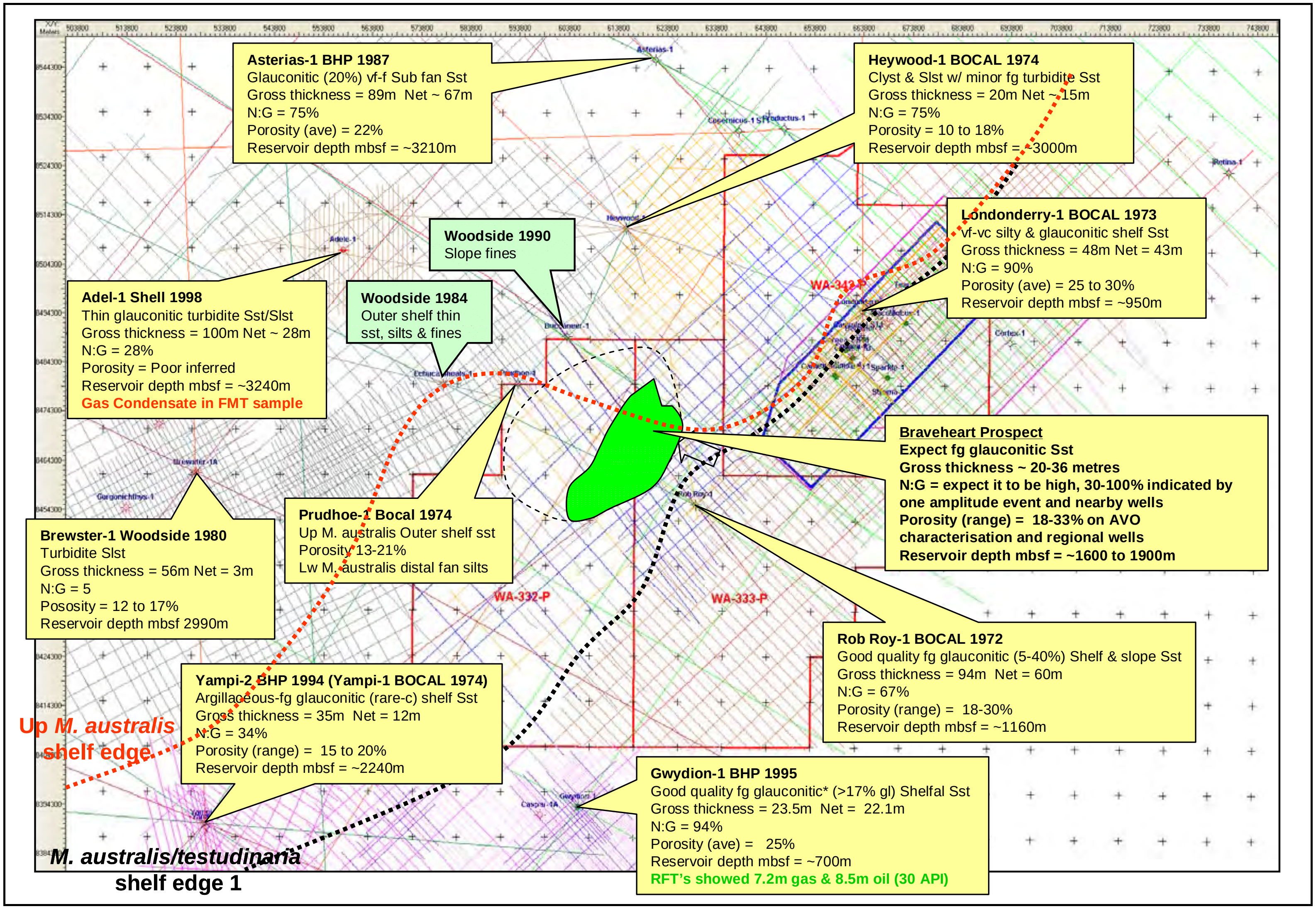

Figure 18 - *M. australis* sandstones depositional facies and reservoir parameters

7. PROSPECT VOLUMETRIC AND RISK ANALYSIS

7.1 Braveheart Prospect

The Braveheart Prospect is a stratigraphic play involving the *M. australis* Barremian Echuca Shoals Formation (Figure 9). The possibility of good quality reservoir exists in this section. A closure in the range of 80-300 km^2 is thought to be representative based on the seismic amplitudes and the AVO analysis. The P10 area was constrained by the high amplitude area and a water contact at 1640 metres. The P90 was defined using a water contact at 1700 metres and the extent of the interpreted sand body pinchout.

7.2 Braveheart Prospect Risking

The critical risk is considered to be the seal risk with both top seal and base seal required to contain hydrocarbons. In particular the base seal, this could be problematic due to the deposition of the thickest Braveheart sediments along the front of the shelf (Figure 13). This deposition may have caused some reworking of the underlying shales. Also the possibility of a feeder channel existing and located between the available seismic lines, and therefore causing an up-dip leakage cannot be ruled out. The predicted reservoir section although not seen in the immediately located Up-dip and down-dip wells would seem relatively low risk from the known depositional environment derived from the regional wells. The size and the geometry of the body is reasonably well constrained despite the low density seismic coverage. Charge is considered low risk with migration of hydrocarbons to the prospect likely due to hydrocarbons proven both up-dip and down-dip from the prospect and its location on the predicted migration route. In general the seismic amplitudes and AVO results are encouraging with regards to hydrocarbon content. However, the risk of residual hydrocarbons remaining after migration through the prospect and giving the observed seismic and AVO response is a strong possibility. The risk analysis results are shown in Table 12.

	Low Estimate	Best Estimate	High Estimate	Mean Estimate
Prospective Recoverable Gas (bscf)	501	1322	2973	1564
Prospective Recoverable Condensate (mmbbls)	23	64	153	78

Table 10 – Unrisked gas case volumes of Braveheart Prospect

	Low Estimate	Best Estimate	High Estimate	Mean Estimate
Prospective Recoverable Oil (mmbbls)	150	397	897	472
Prospective Recoverable Associated Gas (bscf)	28	78	184	95

Table 11 – Unrisked oil case volumes of Braveheart Prospect

Risk Component	Percent
Trap	70
Charge	90
Reservoir	72
Seal	27
Overall Chance of Success	12%

Table 12 - Chance of success of Braveheart Prospect

8. DECLARATIONS

Independence and Qualifications

RPS Energy 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 Energy 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 (Director of Consulting) of RPS Energy Australia/SE Asia has supervised the evaluation.

David Guise is a registered Professional Engineer with over 30 years of domestic and international petroleum engineering and operating experience in both onshore and offshore environments. He has substantial experience and knowledge of field development planning, production optimisation and reserve estimation, as well as new venture identification and evaluation. David holds a Diploma of Technology (Petroleum Technology) from the Southern Alberta Institute of Technology and a B.Sc. in Petroleum Engineering from the University of Wyoming.

Other RPS Energy employees involved in this work hold at least a Masters Degree in geology, geophysics, petroleum engineering or a related subject and have at least five years of relevant experience in the practice of geology, geophysics or petroleum engineering.

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. However, RPS Energy is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property.

In estimating oil in place (STOIIP), and Resources we have used the standard petroleum engineering techniques. We have estimated the degree of uncertainty inherent in the measurement and interpretation of the basic data and have calculated a range of petroleum initially in place and recoverable.

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.

Sources of Information

This report is based upon information which was provided by the licence operator Exoil Limited, from public domain information and proprietary data from within RPSE data bases.

RPSE is not in a position to guarantee the accuracy of data supplied by the operator or independent open file sources.

Only limited new mapping has been carried out in order to address the validity of the operators interpretation and to address additional potential within the block. All data supplied were reviewed and audited with due diligence to provide appropriate confidence in their validity.

9. REFERENCES

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10. APPENDIX A: GLOSSARY OF TERMS AND ABBREVIATIONS

API	American Petroleum Institute
B	billion
bbl(s)	barrels
bbls/d	barrels per day
B_g	gas formation volume factor
B_o	oil formation volume factor
bopd	barrels of oil per day
Bscf	billions of standard cubic feet
condensate	liquid hydrocarbons which are sometimes produced with natural gas and liquids derived from natural gas
GIIP	Gas Initially in Place
GOR	gas/oil ratio
GRV	gross rock volume
GWC	gas water contact
HI	Hydrogen Index
H_2S	Hydrogen sulphide
KB	Kelly Bushing
km	kilometres
km^2	square kilometres
M	thousand
MM	million
MD	measured depth
mD	permeability in millidarcies
m^3	cubic metres
MMscf/d	millions of standard cubic feet per day
msec	milliseconds
NTG	net to gross ratio
NPV	Net Present Value
OWC	oil water contact
petroleum	deposits of oil and/or gas
phi	porosity fraction
PVT	pressure volume temperature
RFT	repeat formation tester
scf	standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	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
STOIIP	stock tank oil initially in place
S_w	water saturation
TOC	Total Organic Carbon
Tscf	trillion standard cubic feet
TVDSS	true vertical depth (sub-sea)
TWT	two-way time

11. APPENDIX B: PROBABILISTIC RESERVES INPUT DATA AND RESULTS

BRAVEHEART_OIL_CASE

Country:	Australia	Prospect/Field:	BRAVEHEART_OIL_CASE	
State:		Reservoir:	AUSTRALIS	
Block:	WA-332-P AND WA-333-P	Hydrocarbons:	Oil	
Basin:	BROWSE	Prospect class:	Unclassified	
Play:	M.AUSTRALIS SSTS	Reserve class:	Prospect	
Licence:	WA-332-P WA-333-P	On/offshore:		
Production Interest:	100.00	Depth datum:	Mean sea level	
		Landfall:		
Exploration Interest:	100.00	Facilities @:		km
		Water depth:	120	m
Operator:		Target depth:	1500	m

Summary of Results

	GRV	Oil-in-Place	Total Rec. Oil		Total Rec. Gas	
	Whole Trap	Whole Trap	Whole Trap	NRI	Whole Trap	NRI
	acre-ft	mmstb	mmstb	mmstb	bcf	bcf
Technically successful						
P90:	1260523	516	150	150	28.0	28.0
P50:	2473690	1335	397	397	77.8	77.8
P10:	4601003	2957	897	897	184	184
Mean:	2717080	1572	472	472	94.6	94.6
Risked mean:			57.8	57.8	11.6	11.6

Chance of Geological Success GPOS: 12%
Overall Chance of Success EPOS 12%

Comments:

REP file: t:\active\aci02121.01 braveheart cpr\subsurface\volumetrics\braveheart_oil.ppr
Author: User Name Date: 10/09/08 Appraiser: B Diamond Reference:
5.12d

BRAVEHEART_OIL_CASE

Country:	Australia	Name:	BRAVEHEART_OIL_CASE
Block:	WA-332-P AND WA-333-P	Segment:	WHOLE
Basin:	BROWSE		
Play:	M.AUSTRALIS SSTS	Hydrocarbons:	Oil

Input Data

Variable	Unit	Shape	min	P90	P50	P10	max	mode
GRV	km2.m	Lognor	624	1573	3134	6244	[8000]	2347
Deg. of fill	%	Single	100	100	100	100	100	100
Net-to-gross	%	Normal	[0]	30.0	60.0	90.0	[100]	60.0
Porosity	%	Triang	18.0	20.4	23.9	28.9	33.0	22.0
Sw	%	Triang	20.0	25.5	32.7	42.3	50.0	30.0
FVF (Bo)	vol/vol	Triang	1.10	1.18	1.27	1.35	1.40	1.30
GOR	scf/stb	Triang	100	145	200	255	300	200
Oil rec fac	%	Triang	20.0	24.5	30.0	35.5	40.0	30.0

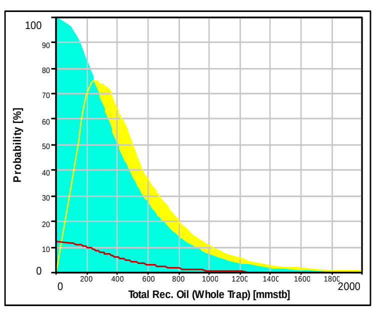
Risk Factors

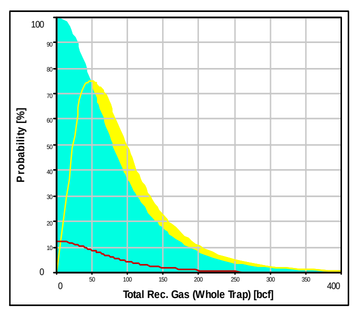
Play Chance:	**100%**	Prospect Specific Chance:	**12%**
Reservoir:	100%	Trap:	70%
Source:	100%	Reservoir:	72%
Regional Seal:	100%	Seal:	27%
		Charge:	90%

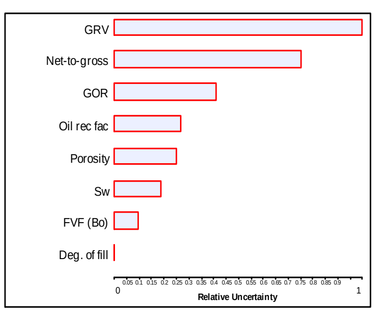
Chance of Geological Success GPOS: **12%**

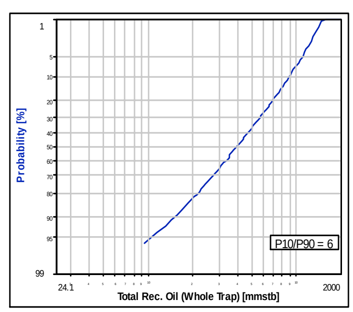
Economic Criteria

No economic minima applied









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BRAVEHEART_GAS

REP for Windows

Country:	Australia	Prospect/Field:	BRAVEHEART_GAS
State:		Reservoir:	AUSTRALIS
Block:	WA-3321-P and WA-333-P	Hydrocarbons:	Gas
Basin:	BROWSE	Prospect class:	Frontier
Play:	M.AUSTRALIS SST FAN	Reserve class:	Prospect
Licence:	100	On/offshore:	
Production Interest:	100.00	Depth datum:	Mean sea level
		Landfall:	
Exploration Interest:	100.00	Facilities @:	km
		Water depth:	130 m
Operator:	BATAVIA OIL AND GAS	Target depth:	1500 m

Summary of Results

	GRV	Gas-in-Place	Total Rec. Oil		Total Rec. Gas	
	Whole Trap	Whole Trap	Whole Trap	NRI	Whole Trap	NRI
	acre-ft	bcf	mmcm	mmcm	bcf	bcf
Technically successful						
P90:	1260523	730	3.58	3.58	501	501
P50:	2473690	1895	10.2	10.2	1322	1322
P10:	4601003	4217	24.3	24.3	2973	2973
Mean:	2717080	2231	12.4	12.4	1564	1564
Risked mean:			1.52	1.52	191	191

Chance of Geological Success GPOS: 12%
Overall Chance of Success EPOS 12%

Comments:

REP file: t:\active\aci02121.01 braveheart cpr\subsurface\volumetrics\braveheart_gas.ppr
Author: User Name Date: 10/09/08 Appraiser: Reference: 5.12d

BRAVEHEART_GAS

Country:	Australia	Name:	BRAVEHEART_GAS
Block:	WA-3321-P and WA-333-P	Segment:	WHOLE
Basin:	BROWSE		
Play:	M.AUSTRALIS SST FAN	Hydrocarbons:	Gas

Input Data

Variable	Unit	Shape	min	P90	P50	P10	max	mode
GRV	km2.m	Lognor	624	1573	3134	6244	[8000]	2347
Deg. of fill	%	Single	100	100	100	100	100	100
Net-to-gross	%	Normal	[0]	30.0	60.0	90.0	[100]	60.0
Porosity	%	Triang	18.0	20.4	23.9	28.9	33.0	22.0
Sw	%	Triang	20.0	25.5	32.7	42.3	50.0	30.0
Dry gas FVF (1/Bg)	vol/vol	Triang	160	178	200	222	240	200
NGL/gas ratio	bbl/mmcf	Triang	20.0	33.4	50.0	66.6	80.0	50.0
Gas rec fac	%	Normal	46.6	60.0	70.0	80.0	93.4	70.0

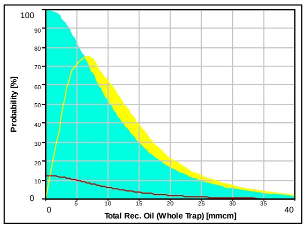
Risk Factors

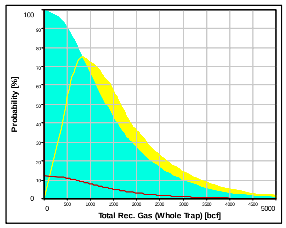
Play Chance:	**100%**	Prospect Specific Chance:	**12%**
Reservoir:	100%	Trap:	70%
Source:	100%	Reservoir:	72%
Regional Seal:	100%	Seal:	27%
		Charge:	90%

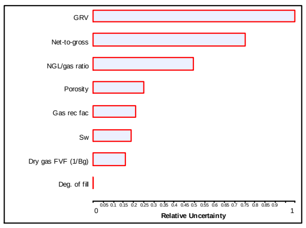
Chance of Geological Success GPOS: **12%**

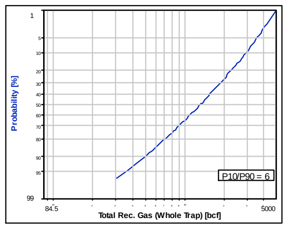
Economic Criteria

No economic minima applied









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Author: User Name Date: 10/09/08 Appraiser: Reference: 5.12d

SECTION 8: BUSINESS AND INVESTMENT RISKS

These risks are not necessarily exhaustive.

Proposing Investors should realise that any company with resource-based operations is subject to a wide range of risks, many of which may not be foreseeable.

The business operations of the Company are subject to risks which may impact adversely on its future performance. These risks may adversely affect the value of any shares in the Company.

Proposing Investors should read this document carefully and in its entirety, with particular emphasis on the risk factors detailed herein, before deciding to invest in the Company.

Proposing Investors should understand that the value of any securities invested in by them after admission of the Company to the Official List of NSX will depend on factors beyond their control and beyond the immediate control of the Board of Directors of the Company. Proposing Investors face the risk that, while the Board will seek to achieve its stated aims, they may not be able to do so.

Proposing Investors should consider the contents of this Information Memorandum in light of their personal circumstances (including financial and taxation affairs) and seek professional advice from their accountant, lawyer or other professional adviser before deciding whether to invest.

In common with most resource companies, risks associated with investment in the Company include:

Share price risks. Proposing Investors should recognise that the prices of shares fall as well as rise. Many factors affect the price of shares including local and international stock markets, movements in interest rates, economic and political conditions and investor and consumer sentiment. Potential Investors will be aware that in the last 12 month period there has been an unprecedented level of volatility on world stock markets and that no predictions can be made as to when that period of volatility will end.

Investment risks generally. Investment is subject to risks of a general nature relating to investment in shares and securities and especially where the company in which the investment is made has a small market capitalisation, such as the case with the Company.

Risks related to investment in resources. Exploration and/or development of resources, particularly oil and gas, the area of the Company's activities, are subject to high levels of risk.

Fiscal risks. These risks involve the imposition of additional taxes, imposts and other charges by government from time to time relating to revenue or cash flow. Industry profitability can be affected by changes in tax policies and the interpretation and application thereof.

Macro economic and political factors. Apart from exchange risks, there are a wide range of other macro economic and political factors beyond the control of the Company which will affect the Company's operations. These include the consequences of terrorist and other activities, which themselves impact adversely on the global economy, demand for commodities, particularly oil and gas, and sharemarket conditions and share prices generally.

Risks relating to commodity prices. Commodities, particularly oil and to a lesser extent gas, are subject to high levels of volatility in price and demand. While oil prices rapidly increased over the past year, reaching record levels, Proposing Investors should understand that those prices can (and have) also decline with equal rapidity.

Political and other factors. These risks include those such as changes in levels of consumer confidence, which affect consumption patterns and consequently demand for a wide range of products, including commodities such as oil and gas. In the event of a major worldwide recession, demand for oil and gas would be affected, with consequent effects on prices which could impact on the viability of the Company's operations: even assuming that commercially exploitable reserves were established.

Sufficiency of funding. The Company will inevitably need to raise significant additional capital to implement and complete its business plans and meet all work and expenditure commitments on the Permits. This requirement to raise additional capital has two consequences for Proposing Investors. First, the requirement to raise additional capital will result in their shareholding in the Company (possibly) being diluted. Second, if additional capital is not raised then the Company's operations will not be able to be funded, with the result that their investment may significantly decrease in value. The total amount of capital that may be required to be raised is not presently able to be ascertained, as it will depend on the success or otherwise of the Company's proposed operations. The work commitments and obligations in relation to the Permits is set out in Section 4, together with the statement in Section 5 that expenditure in 2009/2010 and subsequent periods will be dependent in part on the results of exploration activities from time to time, approval of work programs and budgets by the Company's Joint Venture partners and available working capital. It is also specifically stated in Section 5 that, when required, further funds will be obtained from a combination of sources which may include remaining working capital, farm outs, the proceeds of further share issues and the exercise of the existing options. In the case of field development capital expenditure, funding may need to be via project loan finance. The Directors consider it reasonable to anticipate that, if the Company achieves any significant level of success in its operations, the existing options would be exercised.

The success of the Company will also depend upon it having access to sufficient development capital (in the event of a commercial discovery), being able to maintain title to its Permits and obtaining all required approvals for its activities.

Contract risks. The Company will operate through a series of contractual relationships with operators, technical experts, project managers and contractors generally. All contracts carry risks associated with the performance by the parties of their obligations as to time and quality of work performed. Given that the Company is in joint venture with various other parties and has, or will, enter into farm out agreements where its obligations are assumed by others, the incapacity of those joint venturers or farminees to meet contracted obligations would adversely affect the Company's capacity to carry out its own activities.

Regulatory risks. Operations by the Company may require approvals from regulatory authorities which may not be forthcoming, either at all or in a timely manner, or which may not be able to be obtained on terms acceptable to the Company. While the Company can reasonably believe that all requisite approvals will be forthcoming, and whilst the Company's obligations for expenditure will be predicated on any requisite approvals being obtained, Proposing Investors should be aware that the Company cannot guarantee that any or all requisite approvals will be obtained. A failure to obtain any approval would mean that the ability of the Company to participate in or develop any project, or possibly acquire any project, may be limited or restricted either in part or absolutely. Although the Company can reasonably believe that relevant approvals will be forthcoming, no certainty exists that this will be so.

Litigation. The Company is presently not involved in litigation and the Directors are not aware of any basis on which any litigation against the Company may arise. However, there is always the risk that litigation may occur as a result of differing interpretations of obligations or outcomes.

Exploration and drilling risks. Petroleum exploration involves significant inherent risks in predicting the location and nature of potential petroleum accumulations in the sub-surface. The Company cannot give any assurance that its exploration programme will result in the discovery of any accumulation of oil or gas, nor that any discovery will be commercially viable or recoverable. Risks in relation to drilling operations include break-downs, delays due to weather or sea conditions and shortages of critical equipment or materials. There are also the financial and environmental risks of drilling incidents such as blow-outs, fires and oil spills. The Company mitigates these risks via its safety and environmental policies, plans and procedures and will arrange appropriate insurances for particular risks. The Company gives no assurance against the occurrence of any of these or other adverse events.

In the event that exploration programmes prove to be unsuccessful, this will likely lead to: a diminution in the value of any of the Company's Permits subject to such unsuccessful exploration activities; a reduction in the cash reserves of the Company by virtue of the costs of such activities; possible increased difficulty in raising additional funds following any such unsuccessful activity (particularly drilling); and possible relinquishment of Permits.

Discovery risks. Any discovery may not be commercially viable or recoverable. For a wide variety of reasons, not all discoveries are commercially producible.

Production risks. The Company currently has no petroleum production interests. It must also be understood that no reserves, resources or contingent resources have been defined within any of the Permits in which the Company has an interest.

Therefore, there can be no assurance given that the Company will achieve production from any of the Permits it has an interest in as referred to in this Information Memorandum. Even if a discovery well is drilled on any of the Permits, the capacity of the Company to achieve production will depend on a wide range of factors in addition to a successful exploration outcome. These factors include (but are not limited to) development decisions, capital costs and operating costs that may be applicable to the individual projects and the capacity of the Company to fund those costs.

If production is achieved then unanticipated problems may increase extraction costs and reduce anticipated recovery rates. In some cases, increases in costs, whether in conjunction with falling prices or otherwise, may result in the discovery of a hydrocarbon accumulation not being commercial or ceasing to be commercial.

Reserve calculation risks. The Company has no reserves at present. However, even if it is successful at some time in the future in establishing reserves from any future discovery, it should be recognised that there are numerous difficulties inherent in estimating reserves. Any future statements by the Company as to reserves, which might follow on any future discovery, when and if made by the Company, should at best be regarded as preliminary indications or possibilities and not be relied on. The variables on which estimates of reserves are made include a number of factors and assumptions such as historical production, comparisons with production from other producing areas, assumed effects of regulation by government agencies, assumptions regarding future oil and gas prices and future operating costs, all of which may vary considerably from actual results. Assumptions that affect either the cost of recovery or the viability of recovery of any resource will affect any calculation of reserves.

Environmental compliance and risks. In carrying out operations, the Company and its Joint Venture partners will be required to comply with the *Environment Protection and Biodiversity Conservation Act 1999* (Cwth) ("EPBC Act") which specifies and regulates the environmental protections needed to be put in place by operators to avoid and minimise adverse environmental impact from those operations. The EPBC Act sets out stringent conditions which must be complied with by operators and imposes rigid conditions which must be met before operations can commence. In the event of breaching any such conditions, the Company may be liable to prosecution and the imposition of penalties.

Further, following cessation of any production from future operations, the Company will be required to participate in clean-up programmes resulting from any contamination from operations in which it participates, removal of disused plant and equipment and where necessary, restoration of the environment that has been disturbed in the course of operations. The cost of that participation may be considerable if operations result in significant environmental liabilities being incurred. In such a case, any allowance made for rehabilitation could possibly be inadequate.

Operational risks. These include the possibility of environmental accidents, the risk of unexpected mechanical failure or equipment breakdown resulting in loss of production and additional expense generally, unexpected interruption to or imposition of onerous conditions on access, industrial disputes and resultant increases in costs of operation.

Climatic and geographic risks. All of the Company's Permits are situated in offshore areas. Operations in these areas are generally more prone to being affected by adverse climatic conditions: whether tropical, as in offshore Western Australia; or cool temperate, such as in Bass Strait. In all such locations local weather conditions can have adverse effects on the ability to operate.

Insurance. The Company's operations will expose it to risks and hazards typically associated with exploration for and development and production of hydrocarbons. In accordance with customary industry practices, the Company intends to maintain insurance against various of the risks associated with drilling. The availability of insurance and the rates at which insurance may be available will determine which losses are insured against and in what amount. The occurrence of any significant event which is not insured against could seriously harm the Company and its operations and adversely impact on its financial condition.

Title and tenement risks. A risk exists that some or all of the tenements (i.e. Permits) that the Company holds or has interests in may, when required to be renewed, not be renewed by the regulatory authorities for various reasons. Interests in tenements in Australia are governed by the respective State government legislation and are evidenced by the granting of tenements through the issuing of a lease or licence. Each lease or licence is for a specific term and carries with it annual expenditure and reporting commitments, as well as other conditions requiring compliance. Consequently, the Company could lose title to, or its interests in, tenements if licence conditions are not met or if sufficient funds are not available to meet expenditure commitments. Any failure to comply with the expenditure conditions or with the other conditions on which the licences are held exposes the licences to forfeiture. If the Company does not spend sufficient funds on its tenements as is required by the relevant State governments then those tenements could be cancelled, with the Company receiving no compensation.

In the event that the Company is successful in making a commercial discovery, it will have the right to apply for a production licence over that discovery. The grant of such a licence is also subject to the relevant petroleum legislation in each State and will only be granted on the terms and conditions that the relevant Minister considers appropriate. Once granted, such production licences are liable to forfeiture on breach of any of its conditions.

Finally, even though the terms of any Joint Operating Agreement ("JOA") to which the Company is a party (see Material Agreements in Section 10.1.2) in relation to any tenement interest may impose obligations on the other joint venturers to meet cash calls and pay their share of expenditure, their failure to do so may leave the Company with rights under the relevant JOA against any such co-venturers that may be effectively valueless because the Company may not have the funds to exercise any such rights as permit it to fund and acquire any defaulting co-venturer's interest.

Even where the terms of a JOA are such as they enable non-operator co-venturers the right to remedy any defect, the Company may not have sufficient funds to do so.

Native Title. One of the Company's Permits is subject to Native Title Applications - see Section 4 where limited details are provided. The Company's view is that its operations are unlikely to be adversely affected in a material way by Native Title Applications as all Permit interests are located in offshore waters within the jurisdiction of Australia. However, Prospective Investors should access the National Native Title Tribunal website www.nntt.gov.au to obtain full details of the Applications referred to in Section 4.

No Valuation. No formal or informal valuation has been carried out on the assets of the Company and the Company makes no representation as to the value of those assets. All Proposing Investors and their advisers should make their own assessments as to valuation after having regard to all of the matters contained in this Information Memorandum.

EXOIL LIMITED

ABN 40 005 572 798

FINANCIAL REPORT

FOR THE YEAR ENDED 30 JUNE 2008

EXOIL LIMITED

ABN 40 005 572 798

DIRECTORY

BOARD OF DIRECTORS

J.M.D Willis (Chairman)
E.G. Albers
G.A. Menzies
P.J. Albers

SECRETARY

J.G. Tuohy
Level 21,
500 Collins Street,
Melbourne, Victoria 3000

REGISTERED OFFICE AND PRINCIPAL ADMINISTRATION OFFICE

Level 21, 500 Collins Street,
Melbourne, Victoria 3000

Telephone: +61 (03) 8610 4700
Facsimile: +61 (03) 8610 4799
E-mail: admin@exoil.net

AUDITOR

PKF
Chartered Accountants
Level 14
140 William St
Melbourne, Victoria 3000

INCORPORATED IN VICTORIA

13 March 1980

WEBSITE

www.exoil.net

CONTENTS

FORWARD LOOKING STATEMENTS

This Financial Report includes certain forward-looking statements that have been based on current expectations about future acts, events and circumstances. These forward-looking statements are, however, subject to risks, uncertainties and assumptions that could cause those acts, events and circumstances to differ materially from the expectations described in such forward-looking statements.

These factors include, among other things, commercial and other risks associated with the meeting of objectives and other investment considerations, as well as other matters not yet known to the company or not currently considered material by the company.

RISK FACTORS

Exploration for oil and gas is speculative, expensive and subject to a wide range of risks. There can be no assurance that any well drilled by Exoil will result in the discovery of oil or gas, nor that any discovery will prove to be commercially viable. Individual investors should consider these matters in light of their personal circumstances (including financial and taxation affairs) and seek professional advice from their accountant, lawyer or other professional adviser as to the suitability of an investment in the company.

CHAIRMAN'S REVIEW

Dear Shareholders

Exoil has continued to make solid progress through 2008 and is soon to participate in the drilling of the Spikey Beach Prospect in T38P. We have a 10% free carried interest in this well.

During 2007 – 2008 to date we have:

(i) successfully farmed out Vic/P53 to Stuart Petroleum Limited. This resulted in the drilling of the Bazzard feature within Vic/P53 (Exoil interest 16.6667%) at no cost to the Company;

(ii) drilled Coelacanth in Vic/P45. The farminee, Apache Energy, has returned its interest in Vic/P45 to us. We now again hold 50%;

(iii) entered into an agreement with Beach Petroleum Limited to farmout part of T/38P on terms which will see the Company carried through all of the costs of a well to be drilled in the permit area, with the well timing expected to be in Q4 2008 (Exoil interest 10% in the Beach farmout area);

(iv) acquired a large 2D seismic programme across our Bass Basin permits – 3,000 km in T/37P, 670 km in T/38P. We farmed out the cost of the survey;

(v) acquired 1,100 kms of new seismic in EPP34 in the Otway Basin – the Trocopa Survey.

(vi) identified the exciting and potentially very large 'Braveheart' stratigraphic prospect. We have committed to a 700 km infil 2D program in WA-332-P and WA-333-P and have secured a rig. Braveheart will be drilled in Q3 2009 (Exoil interest 35%);

(vii) continued our assessments of WA-342-P (which contains the known Cornea oil accumulation) (Exoil interest 35%);

(viii) farmed out our interest in WA-359-P to MEO Australia Limited on terms which relieved us of the seismic obligation in that permit. If MEO commits to the drilling of a well in the permit, Exoil can elect to be fully carried through the costs of that well for up to a 15% interest (Exoil interest 20%).

All of these activities are described in more detail in the Directors Report.

The Braveheart 2D seismic survey over WA-332-P and WA-333-P resulted in the identification of the Braveheart prospect for which we have high hopes. Similarly, by reprocessing a large amount of 3D data over Cornea (WA-342-P), we have been able to obtain a much better image over Cornea and have identified a number of additional leads. More recently we have farmed out a small part of WA-332-P and WA-333-P (which contains the Braveheart prospect) in order to fund a programme of infill 2D seismic which will better define the Braveheart prospect. These three permits have attracted considerable interest from substantial industry participants. As of the date of this report we are confident we will be able to farmout an interest in the permits to help fund the drilling costs.

Within T/38P in the Bass Basin, Exoil will be participating in the Spikey Beach well (Exoil interest: 10%).

In the balance of T/38P and across T/37P the Operator for the permits is now busy interpreting the extensive seismic programme (3,660 line kilometres) acquired last summer. We believe this seismic has the potential to reveal significant new features in these permits (Exoil interest: 35%).

The results of the Bazzard well in Vic/P53 were disappointing. That said, the Operator, Stuart Petroleum, was able to accurately pick the formation tops targeted in this well which is a testimony to the work they have done in relation to the notoriously difficult depth conversion challenges in this permit area. We are now working with Stuart to determine the best location for a further well in the permit.

The prospectivity of Vic/P53 has by no means been exhausted. There are further leads and prospects. If we have any drilling success you can be assured we are ready to act quickly to take advantage of such an outcome.

CHAIRMAN'S REVIEW (Continued)

In EPP34 we are still to receive the processed seismic data from our 1,100 kms Trocopa survey. We are hopeful this new seismic will also reveal more about this permit and this part of the Otway Basin.

Looking forward, our preference is to fund major exploration activities by farmout. The farm-out of part of our interest in Vic/P53, T/38P, WA-332-P, WA-333-P, WA-342-P and WA-359-P is a successful realisation of this strategy.

We face choices about how the cost of drilling in WA-332-P, WA-333-P and WA-342-P is to be funded. We are seeking farmin partners for WA-332-P, WA-333-P (the Braveheart prospect) and WA-342-P (the Cornea prospect) but, if conditions permit, we may choose to retain the whole of our present interest by fully funding the wells. Seeking funds through a special purpose company is also a matter we are actively considering.

We are well advanced with our plan to seek a quotation for our Company's securities on the National Stock Exchange. We will advise you once quotation has been achieved. In advance of this action, shareholders approved the splitting of the Company's shares on a 2 for 1 basis.

We recently appointed and welcome Mr J.G. Tuohy as Secretary of the Company.

In summary, 2007 – 2008 has been a year of significant achievement. Looking beyond the current economic turmoil, the future for the company remains exciting.

Yours sincerely

J.M.D. Willis
Chairman
29 October 2008

DIRECTORS' REPORT

The directors present their report together with the financial report of Exoil Limited ("the company") for the year ended 30 June 2008 and the auditor's report thereon.

DIRECTORS

The directors of the Company in office throughout the period and to the date of this report are as follows:

JMD Willis LL.M (Hons) Dip Acc
Chairman
Non-Executive Director

Mr Willis is the principal of an oil and gas consulting company based in Melbourne. Prior to that he was a partner in a leading New Zealand law firm, Bell Gully for more than 25 years where his practice speciality was the upstream oil and gas area, particularly relating to issues concerning gas contracting and the development of oil and gas reserves, joint ventures and upstream petroleum related acquisitions. He has acted for the leading participants in the upstream petroleum industry in New Zealand. He is now active in Australia. With Mr Albers he was co-founder and later a director of Southern Petroleum, a successful New Zealand explorer and partner, now wholly owned by Shell. Director since 2004.

EG Albers LL.B FAICD
Director, Company Secretary

Mr Albers is a company director with over thirty five years experience as a lawyer and administrator in corporate law, petroleum exploration and resource sector investment. During this period Mr Albers has sponsored the formation of companies that have made the original Maari (Moki) oilfield discovery in New Zealand, the Yolla Gas/Condensate discovery in Bass Strait, the Evans Shoal gasfield discovery/appraisal in the Timor Sea, the SE Gobe oilfield development in Papua New Guinea and the Oyong oil/gas discovery in Indonesia. Mr Albers is Chairman of Moby Oil & Gas Limited, Octanex NL, Strata Resources NL and a director of Bass Strait Oil Company Ltd and Cue Energy Resources Ltd. He is also a director of various other private and unlisted public companies. He is a member of the Petroleum Exploration Society of Australia. Director since 1981.

GA Menzies LL.M
Independent Non-Executive Director

Mr Menzies is a barrister and solicitor. He graduated from Melbourne University in 1971 and qualified for admission to the degree of Master of Laws in 1975. He was admitted to practice in 1972. Since 1987 he has carried on practice as a sole practitioner under the name of Menzies & Partners. In the course of his legal practice, Mr Menzies has been involved in a wide range of activities, including takeovers, litigation in respect thereof, numerous capital raisings and corporate reconstructions. He has been involved in the listing of a large number of public companies ranging from junior exploration to substantial mining companies. Over recent years, his activities have focused primarily on corporate reconstructions and capital raisings. Director since 2004.

PJ Albers
Non-Executive Director

Mrs Albers has had more than thirty five years of commercial experience including co ownership and management of a significant primary production operation. She has been a director of a number of corporations, including public companies, over the last fifteen years. Mrs Albers has a background in human resources, health and safety, and in public relations. Director since 1984.

DIRECTORS' REPORT (Continued)

DIRECTORS' MEETINGS

The number of directors' meetings and number of meetings attended by each of the directors of the Company during the financial period were:

Director	Board meetings attended	Board meetings held
EG Albers	1	1
JMD Willis	1	1
GA Menzies	1	1
PJ Albers	1	1

DIRECTORS' INTERESTS

As of 30 June 2008 the relevant interest of each of the directors in the Company is as follows:

Ordinary shares		*Options over ordinary shares*	
EG Albers	40,059,992	EG Albers	100,000
JMD Willis	1,156,250	JMD Willis	200,000
GA Menzies	-	GA Menzies	200,000
PJ Albers	40,059,992	PJ Albers	100,000

As described below, under the Share Capital and Share Options sections of the Directors' Report, the above holdings of shares and options doubled in number on 3 September 2008.

ENVIRONMENT, HEALTH AND SAFETY

The Company has adopted an environmental, health and safety policy and conducts its operations in accordance with the APPEA Code of Practice.

The Company's petroleum exploration and development activities are subject to environmental conditions specified in the Offshore Petroleum Act (2006), associated Regulations and Directions, as well as the Environment Protection and Biodiversity Conservation Act (1999). During the year there were no known contraventions by the Company of any relevant environmental regulations.

CORPORATE GOVERNANCE

As Exoil Limited is not a listed company it is not required to comply with the "Principles of Good Corporate Governance and Best Practice Recommendations" (the CGC Paper) which was issued by the ASX Corporate Governance Council (CGC). However, this statement does outline the main corporate governance practices in place throughout the financial period.

The Directors are responsible for the strategic direction of the Company, the identification and implementation of corporate policies and goals and monitoring of the business and affairs of the Company on behalf of its members. One of the key objectives of the Board is to ensure timely, transparent and accurate communication with all members and compliance with all regulatory requirements.

Given that the Company is small, with limited activities and limited resources, the Board has not established a series of committees to address specific areas of corporate governance such as strategic review, nominations, operations and remuneration. These issues are dealt with by the Board as a whole with any interested directors abstaining or being absent as required either by the Corporations Act or as necessary to avoid conflict or possible breach of their fiduciary duties.

PRINCIPAL ACTIVITY

The principal activity of the Company during the course of the financial year was to acquire and explore areas prospective for oil in offshore waters within the jurisdiction of Australia.

DIRECTORS' REPORT (Continued)

REVIEW AND RESULTS OF OPERATIONS

Company overview

The Income Statement shows a consolidated net loss of $61,296 (2007: $763).

State of affairs

The Company is incorporated and domiciled in Australia and has no employees other than the directors.

The directors are not aware of any other matter or circumstance that has arisen during the financial period or since that has significantly affected or may significantly affect the operations of the Company, the results of those operations or the state of affairs of the Company in subsequent financial years, except as may be stated elsewhere in the financial report.

DIVIDENDS

No dividends have been paid, provided or recommended for payment by the Company during the year and to the date of this report.

SHARE CAPITAL

Issue of Ordinary Shares

No shares have been issued by the Company during the year ended 30 June 2008.

At a general meeting of shareholders held on 3 September 2008 an ordinary resolution was passed subdividing the fully paid issued ordinary shares in the company into two ordinary shares each credited as fully paid up ordinary shares with the effect that issued capital of the company comprises 101,550,526 ordinary fully paid shares at the date of this report.

SHARE OPTIONS

No options were granted during the year ended 30 June 2008. As per above, as described under the Share Capital section of the Directors' Report, on 3 September 2008 the numbers of options issued were doubled and option prices halved as part of the share sub-division. There have been no other changes to the number or price of options to the date of this report.

Unissued shares under option

At the date of this report unissued ordinary shares of the Company under options were:

Expiry date	Exercise price	Number of options
31 December 2009	$0.15	2,350,000
31 December 2009	$0.20	1,350,000
		3,700,000

These options do not entitle the holder to participate in any share issue of the company or any other body corporate and expire on the earlier of their expiry date, if the holder ceases to be an "Eligible Person" or six months (or such longer period as the Directors may determine) from when the holder ceases to be an Eligible Person due to retrenchment or normal retirement from the workforce. An Eligible Person is defined as executive officers of Exoil Limited including employees, directors, secretaries and seconded personnel who take part in the management of Exoil Limited

LIKELY DEVELOPMENTS AND EXPECTED RESULTS

The consolidated entity's strategy is to seek out substantial opportunities in the upstream oil and gas industry and to maximise the monetisation of the consolidated entity's current exploration interests and its investments in that sector.

The likely developments in the consolidated entity's operations in future years and the expected result from those operations are dependent on exploration success in the permit areas in which the consolidated entity holds an interest.

DIRECTORS' REPORT (Continued)

INDEMNIFICATION AND INSURANCE OF DIRECTORS

During the year and to the date of this report, the company did not pay premiums in respect of contracts insuring directors of the company against liabilities arising from their position of directors of the company.

REVIEW OF PETROLEUM EXPLORATION ACTIVITIES

Vic/P53 - Offshore Gippsland Basin - 50% interest reducing to 16.6667% – Stuart is the operator

The Vic/P53 Joint Venture now consists of:

Stuart	50% and Operator
Exoil Limited	16.6667%
Moby Oil & Gas Limited	8.3333%
Cue Petroleum Pty Ltd	25% (15% of this interest is held by Cue Petroleum to satisfy ACOC back-in rights pursuant to an agreement between Cue Petroleum and ACOC)

Stuart was appointed as Operator and met 100% of the costs the Bazzard 1 well. Stuart can withdraw from the permit, at its election, 90 days after the conclusion of this well. Stuart paid a further US$1,150,000 to Moby and Exoil (in the ratio of⅔ to Exoil and ⅓ to Moby). This enable d Moby and Exoil to meet pre-existing contractual obligations to Cue Petroleum. The Farminee will assume it's pro rata share of the overriding royalty (4%) obligations of Exoil and Moby to the original permit holder, Australia Crude Oil Company, Inc.

Vic/P45 - Offshore Gippsland – 50% interest – Exoil is the operator

The Vic/P45 Joint Venture consists of:

Moby Oil & Gas Limited	50%
Exoil Limited	50% (Operator)

Apache met 100% of the costs of the Coelacanth-1 well. Apache then elected to withdraw from a further commitment to drill a second well and is obligated to reconvey the farmout interest (66.6668%) to Moby and Exoil.

While remaining prospects are ready for drilling, the very tight market for offshore drilling rigs has pushed future Vic/P45 drilling activity into 2009.

T/37P and T/38P Bass Basin, Offshore from Tasmania - 35% interest – Cue Energy is the operator

The T37P and T38P Joint Venture consists of:

Cue Energy Resources Ltd	50%
Exoil Limited	35%
Gascorp Australia Pty Ltd	15%

Exoil (35%) with Cue Energy Resources Ltd (50%), and now Gascorp Australia Pty Ltd (15%), hold two adjacent petroleum permits, T/37P and T/38P, located in the Bass Strait region, north of Tasmania and east of King Island. Each area consists of 40 graticular blocks, covering areas of approximately 2,670 kms^2 (T/37P), and 2,655 kms^2 (T/38P). Water depths across the areas are less than 75 metres. The T/37P permit is immediately adjacent to the Yolla gas condensate field which has recently begun production. Yolla also contains oil.

Interpretation of the existing seismic data has been completed and both time and depth maps have been constructed and integrated with existing well information. Prospects and leads have been identified and have been analysed.

Exoil joined with a group of companies which jointly mobilized a seismic vessel to the Gippsland, Bass and Otway areas. 3,000 kms of new seismic data was acquired in T/37P and 670 line kms of seismic data in T/38P. Exoil farmed out its share of cost of this survey and as a consequence its interest in the Permits and Joint Venture has reduced to 35%.

DIRECTORS' REPORT (Continued)

The T/38P permit is immediately south of the producing Yolla gas condensate field. The permit contains the Pelican gas condensate discovery. Interpretation of the existing seismic data has been completed and both time and depth maps have been constructed and integrated with existing well information. Prospects and leads have been identified and have been analysed.

Beach Petroleum Limited agreed to farmin to part of T/38P and will earn an 80% interest in a defined portion (Spikey Beach blocks) of the T/38P permit by paying for the drilling of the Spikey Beach-1 exploration well. It will be operated by Beach and is expected to be drilled in November 2008. Exoil will hold a 10% interest in the Spikey Beach blocks.

The Bass Basin is a moderately explored basin with 33 wells drilled since 1965. The basin has a drilling density of approximately one well per 1,320 kms^2.

The Company's target in these Bass Basin permits is oil. Significantly, a number of wells in the Bass Basin have either found reservoired oil or encountered strong live oil indications.

Browse Basin, Offshore from Western Australia – 29.75% interest – Exoil is the operator

Exoil, through its wholly owned subsidiary, Hawkestone Oil Pty Ltd, holds a 29.75% interest in three contiguous permits (WA-332-P, WA-333-P and WA-342-P) held by the Browse Joint Venture.

The Browse Joint Venture consists of:

Hawkestone Oil Pty Ltd (Operator)	29.75%
Batavia Oil & Gas Pty Ltd	29.75%
Alpha Oil & Natural Gas Pty Ltd	17.00%
Gascorp Australia Pty Ltd	15.00%
Goldsborough Energy Pty Ltd	8.50%

The Browse Joint Venture previously acquired the Braveheart 2D seismic program over the permits and has obtained available open file reports and basic 2D and 3D seismic data acquired by previous explorers. This includes 2,000 km² of high quality 3D seismic known as the Cornea 3D survey which is held by the Browse Joint Venture. The data sets have been integrated with the acquisition and processing of the Braveheart 2D seismic survey to infill the existing grid of data, with lead specific coverage. Geological and geophysical evaluation of the Permits is continuing. AVO studies over the Braveheart Prospect which straddles WA-332-P and WA-333-P have provided a drilling target for the Braveheart Prospect. The joint venture has committed to a drilling rig for the drilling of Braveheart 1 in late 2009. In the meantime, the joint venture has elected to acquire a further 700 line kms of new 2D seismic as infill in WA-332-P and WA-333-P. This was funded by a farmout of 15% of each of WA-332-P, WA-333-P and WA-342-P.

In WA-342-P the Cornea Field was discovered by the early exploration wells Cornea-1, 1B and 2. They established the presence of a minimum 25 metres gas column and a minimum 18 metres oil column in the Albian *P. ludbrookiae* sandstones of the Jamieson Formation. The field is a large drape feature enclosing Albian sandstones. It accumulated 18 to 22 degree API oil derived from Early Cretaceous, Echuca Shoals Formation and possibly Late Jurassic source rocks in the Heywood Graben, located over 60 kilometres to the west. The field is split into three main structural components – Cornea South, with gas and oil, Cornea Central with gas and oil and Cornea North with gas and no underlying oil presence.

Similar Albian sandstone drape features have been recognised in the McDuff, Koolan North, Koolan and Koolan South leads on reprocessed Cornea 3D seismic, in a basement high trend parallel with the Cornea Field. These drape leads occur over lower basement topography than in the Cornea structure and as such also have the better quality Aptian to early Albian sandstone reservoirs draped over basement with the intervening seal interpreted to be intact. This potentially allows stacked hydrocarbon pools, as indicated by the AVO anomaly in the McDuff Lead which was not observed in the Cornea Field.

The joint venture has reprocessed approximately 1,000 kilometres of the Cornea 3D data in WA-342-P.

DIRECTORS' REPORT (Continued)

EPP34 Otway Basin, Offshore from South Australia - 15% interest – Exoil is the operator

The EPP34 Joint Venture consists of:

Exoil Limited (Operator)	15%
Moby Oil & Gas Limited	20%
National Energy Pty Ltd	15%
United Oil & Gas Pty Ltd	30%
Gascorp Australia Pty Ltd	10%
National Gas Australia Pty Ltd	10%

The Trocopa seismic grid of 1,100 km of new 2D data was acquired. Exoil farmed out its share of cost of the survey and has thus reduced its interest to 15%. Interpretation has focused on the northern shelfal section of the block, targeting the Early Cretaceous Pretty Hill Sandstone.

EPP35 Otway Basin, Offshore from South Australia – Exoil is the Operator

The EPP35 (Troas) Joint Venture consists of:

Exoil Limited (Operator)	20%
Gascorp Australia Pty Ltd	40%
National Energy Pty Ltd	20%
Moby Oil & Gas Limited	20%

EPP35 contains the Troas Gas Accumulation, where gas indications were noted over more than 1,000 metres of sedimentary section. It therefore has a proven hydrocarbon system in place. Our focus has been on the Troas Deep Prospect. The joint venture plan to shoot a 325 km² 3D seismic grid over the Troas Deep complex. We have agreed to farm out 10% interest in the permit in return for Gascorp meeting our remaining 20% share of the cost. The permit is endowed with a wide range of potential prospects, with fair to good seismic and well data coverage. The permit is located approximately 100 km from the gas pipeline to Adelaide.

EPP36 Otway Basin, Offshore from South Australia – Exoil is the Operator

The EPP36 Joint Venture consists of:

Exoil Limited (Operator)	20%
Gascorp Australia Pty Ltd	40%
National Energy Pty Ltd	20%
Moby Oil & Gas Limited	20%

EPP36 is a deep water area, parallel to the Morum Sub-basin. It is thought to have excellent reservoir potential for stacked plays in thick Upper Cretaceous section. Because of its proximity to the Morum Sub-basin, EPP36 is postulated to have scope for marine influenced source rock in deep water. We have agreed to farm out 10% of our interest in the permit in return for Gascorp meeting our remaining 20% share of the cost. A 1,100 line kilometre 2D survey is planned for the 2008/2009 summer.

Vic/P61 Otway Basin, Offshore from Victoria - 30% interest – Exoil is the operator

The Vic/P61 Joint Venture consists of:

Exoil Limited	30% and Operator
Gascorp Australia Pty Ltd	30%
Moby Oil & Gas Limited	20% earning pursuant to farmin
Octanex N.L.	10% earning pursuant to farmin
Strata Resources N.L.	10% earning pursuant to farmin

DIRECTORS' REPORT (Continued)

Vic/P61 is located in the offshore Otway Basin, some 50-60 kilometres southwest of Port Campbell. The area comprises 30 graticular blocks covering approximately 1874 kms^2, and is situated on the shelf margin of the Otway Basin, where water depths vary between 80-500m. The block's eastern boundary is close to gas discoveries and new developments at Minerva, Geographe, Thylacine and Casino. Seismic surveys over the block are entirely 2D and vary in quality and extent.

The Joint venture had planned to acquire 1,000 line Kms of new 2D seismic in Q1 2008. Unfortunately, we were not able to obtain environmental approvals for this survey because of concerns about the effects of seismic on blue and southern right whales. We are working on the issues but it remains to be seen whether we can obtain the approvals we need to acquire more seismic.

WA-359-P Dampier Basin / Rankin Trend, Offshore from Western Australia - 20% interest – MEO Australia is the Operator.

Participants in the permit are:

North West Shelf Exploration Pty Ltd (MEO Australia Limited Subsidiary)	60%
Cue Exploration Pty Ltd	20%
Exoil Limited	20%

WA-359-P, in the Dampier Basin offshore, from Western Australia, covers an area of approximately 1,200 kms^2 in water depths of less than 500m.

Interpretation of the existing seismic data has been completed and regional time and depth maps have been constructed and integrated with well information. Prospect mapping is complete and prospect packages have been prepared. A scoping economic study for potential hydrocarbon accumulations has also been completed.

A small 2D seismic survey was acquired in the permit.

A wholly owned subsidiary of MEO Australia Limited (MEO) farmed into Exoil's 50% interest in permit WA-359-P. MEO will earn a 60% interest in each permit by meeting the year-3 commitment seismic (now completed) and electing to fund 90% of the cost of drilling the first exploration well in the permit. As of the date of this report MEO has not elected to fund a well.

MEO became the operator.

SUBSEQUENT EVENTS

At a general meeting of shareholders held on 3 September 2008 an ordinary resolution was passed subdividing the fully paid issued ordinary shares in the company into two ordinary shares each credited as fully paid up ordinary shares with the effect that the issued capital of the company comprises 101,550,526 ordinary fully paid shares from that date. The share sub-division also impacted Options. The numbers of option issued were doubled and option prices halved, also on 3 September 2008.

On 18 September 2008 Stuart Petroleum Limited, as operator of the Vic/P53 Joint Venture, announced that the Bazzard-1 well would commence drilling on or about 19 September 2008. The well was completed on 8 October 2008, when it was plugged and abandoned.

DIRECTORS' REPORT (Continued)

AUDITOR'S INDEPENDENCE DECLARATION AND NON-AUDIT SERVICES

The auditor's independence declaration, as required under section 307C of the Corporations Act 2001, is attached to this report.

During the year $2,000 was paid to the auditor for advice on tax compliance.

Signed in accordance with a resolution of the Directors.

G.A. Menzies
Director

Melbourne, 29 October 2008

DIRECTORS' DECLARATION

In accordance with a resolution of the directors of Exoil Limited, I state that:

In the opinion of the directors:

(a) the financial statements and notes of the company and the consolidated entity are in accordance with the Corporations Act 2001 and:

(i) give a true and fair view of the company's and the consolidated entity's financial position as at 30 June 2008 and performance for the year ended on that date; and

(ii) comply with the Accounting Standards and Corporations Regulations 2001; and

(b) the financial report also complies with International Financial Reporting Standards as disclosed in Note 1(a); and

(c) there are reasonable grounds to believe that the company will be able to pay its debts as and when they become due and payable.

On behalf of the Board

G.A. Menzies
Director

Melbourne, 29 October 2008

INCOME STATEMENT
YEAR ENDED 30 JUNE 2008

	NOTE	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
Revenue	2	312,518	314,286	311,583	848,334
Finance costs		(25,563)	(18,735)	(24,349)	(14,610)
Depreciation expense		(13,645)	(9,984)	(13,645)	(9,984)
Other expenses	3	(426,240)	(211,999)	(426,240)	(211,999)
(Loss) profit before tax		(152,930)	73,568	(152,651)	611,741
Income tax benefit (expense)	5	91,634	(74,331)	91,634	(183,050)
(Loss) profit after tax		(61,296)	(763)	(61,017)	428,691

The Income Statement is to be read in conjunction with the Notes to the Financial Statements

BALANCE SHEET
AT 30 JUNE 2008

	NOTE	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
CURRENT ASSETS					
Cash and cash equivalents	22	970,987	113,744	974,743	77,659
Trade and other receivables	6	299,381	105,600	289,140	638,697
TOTAL CURRENT ASSETS		1,270,368	219,344	1,263,883	716,356
NON-CURRENT ASSETS					
Exploration and evaluation assets	7	3,732,656	5,102,468	2,852,385	4,607,028
Property, plant and equipment	8	78,033	26,390	78,033	26,390
Other financial assets	9	25,067	91,791	1,069,293	318,041
TOTAL NON-CURRENT ASSETS		3,835,756	5,220,649	3,999,711	4,951,459
TOTAL ASSETS		5,106,124	5,439,993	5,263,594	5,667,815
CURRENT LIABILITIES					
Trade and other payables	10	528,433	619,332	494,506	555,921
Tax liabilities		-	90,040	-	-
TOTAL CURRENT LIABILITIES		528,433	709,372	494,506	555,921
NON-CURRENT LIABILITIES					
Other payables	10	-	-	-	190,155
Deferred tax liabilities	11	573,861	665,495	573,861	665,495
TOTAL NON-CURRENT LIABILITIES		573,681	665,495	573,861	855,650
TOTAL LIABILITIES		1,102,294	1,374,867	1,068,367	1,411,571
NET ASSETS		4,003,830	4,065,126	4,195,227	4,256,244
EQUITY					
Contributed equity	12	2,959,055	2,959,055	2,959,055	2,959,055
Reserves	13	81,277	81,277	81,277	81,277
Retained earnings		963,498	1,024,794	1,154,895	1,215,912
TOTAL EQUITY		4,003,830	4,065,126	4,195,227	4,256,244

The Balance Sheet is to be read in conjunction with the Notes to the Financial Statements

STATEMENT OF CHANGES IN EQUITY
YEAR ENDED 30 JUNE 2008

	Issued Capital $	Option Reserves $	Retained Earnings $	Total Equity $
CONSOLIDATED				
At 1 July 2007	2,959,055	81,277	1,024,794	4,065,126
Loss for the period	-	-	(61,296)	(61,296)
At 30 June 2008	2,959,055	81,277	963,498	4,003,830
At 1 July 2006	2,892,252	81,277	1,025,557	3,999,086
Shares issued	66,803	-	-	66,803
Loss for the period	-	-	(763)	(763)
At 30 June 2007	2,959,055	81,277	1,024,794	4,065,126
COMPANY				
At 1 July 2007	2,959,055	81,277	1,215,912	4,256,244
Loss for the period	-	-	(61,017)	(61,017)
At 30 June 2008	2,959,055	81,277	1,154,895	4,195,227
At 1 July 2006	2,892,252	81,277	787,221	3,760,750
Shares issued	66,803	-	-	66,803
Profit for the period	-	-	428,691	428,691
At 30 June 2007	2,959,055	81,277	1,215,912	4,256,244

The Statement of Changes in Equity is to be read in conjunction with the Notes to the Financial Statements

CASH FLOW STATEMENT
YEAR ENDED 30 JUNE 2008

	NOTE	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
CASH FLOWS FROM OPERATING ACTIVITIES					
Interest received		80,152	7,632	79,215	1,680
Management fee received		-	20,905	-	20,905
Administration fee received		219,759	279,301	219,759	279,301
Proceeds from tenement farmouts		2,108,133	-	2,108,133	-
Payments to suppliers of exploration services		(774,386)	(699,566)	(356,733)	(479,189)
Payments to other suppliers and employees		(349,982)	(212,562)	(349,983)	(212,560)
Tax paid		(90,040)	-	-	-
Interest paid		(29,687)	(14,611)	(28,470)	(14,611)
Net cash provided by/(used in) operating activities	(i)	1,163,949	(618,901)	1,671,921	(404,474)
CASH FLOWS FROM INVESTING ACTIVITIES					
Payment for office & computer equipment		(69,715)	(2,458)	(69,715)	(2,458)
Proceeds from sale of investments		7,500	-	7,500	-
Net cash used in investing activities		(62,215)	(2,458)	(62,215)	(2,458)
CASH FLOWS FROM FINANCING ACTIVITIES					
Payments to related entities		(244,491)	-	(244,491)	-
Receipts from related entities		-	244,491	-	244,491
Payments on behalf of subsidiary		-	-	(468,131)	-
Net cash (used in) from financing activities		(244,491)	244,491	(712,622)	244,491
Net increase (decrease) in cash assets		857,243	(376,868)	897,084	(162,441)
Cash and cash equivalents at beginning of period		113,744	490,612	77,659	240,100
CASH AND CASH EQUIVALENTS AT END OF PERIOD		970,987	113,744	974,743	77,659

(i) RECONCILIATION OF NET CASH FROM OPERATING ACTIVITIES WITH (LOSS)/ PROFIT AFTER INCOME TAX

	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
(Loss) profit after income tax	(61,296)	(763)	(61,017)	428,691
Adjusted for non cash items:				
Depreciation of plant and equipment	13,645	9,984	13,645	9,984
Net movement in value of investments	59,224	(7,011)	59,224	(7,011)
Management fees	-	-	-	(540,000)
Loss on scrapping of assets	4,427	-	4,427	-
Changes in assets and liabilities:				
(Increase) decrease in receivables	(193,782)	64,190	(190,442)	64,389
(Decrease) increase in tax liabilities	(181,674)	74,331	(91,634)	183,050
Increase in payables	153,593	502	183,075	85,092
Decrease (increase) in exploration expenditure	1,369,812	(760,134)	1,754,643	(628,669)
Net Cash provided by/(used in) Operating Activities	1,163,949	(618,901)	1,671,921	(404,474)

The Cash Flow Statement is to be read in conjunction with the Notes to the Financial Statements

NOTES TO THE FINANCIAL STATEMENTS
30 JUNE 2008

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Exoil Limited is a public company incorporated and domiciled in Australia with its registered office and principal place of business located at level 21, 500 Collins Street, Melbourne, Victoria 3000. The consolidated financial report of the company for the year ended 30 June 2008 comprise the company and its 100% owned subsidiary, Hawkestone Oil Pty Ltd (together referred to as the 'consolidated entity').

The principal activity of the consolidated entity during the year was to acquire and explore areas prospective for oil in offshore waters within the jurisdiction of Australia.

The financial report was authorised by the directors for issue on 29 October, 2008.

(a) Statement of compliance
The consolidated financial report is a general purpose financial report which has been prepared in accordance with Australian Accounting Standards adopted by the Australian Accounting Standards Board ('AASB') and the Corporations Act 2001. The consolidated financial statements and notes comply with IFRS and interpretations adopted by the International Accounting Standards Board.

(b) Basis of preparation
The financial report is presented in Australian dollars and has been prepared on an accruals basis and is based on historical costs modified by the revaluation of selected financial assets for which the fair value basis of accounting has been applied.

The preparation of a financial report in conformity with Australian Accounting Standards requires management to make judgements, estimates and assumptions that affect the application of policies and reported amounts of assets and liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstances, the results of which form the basis of making the judgements about carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

Judgements made by management in the application of Australian Accounting Standards that have a significant effect on the financial report and estimates with a significant risk of material adjustment in the next year are discussed in note 1(p).

The accounting policies set out below have been applied consistently to all periods presented in the financial report.

(c) Going concern
The consolidated entity had working capital of $741,935 as at 30 June 2008. Its future is dependent upon obtaining external finance to fund exploration commitments and operations. The directors believe such sources of finance will be available and have prepared the financial report on a going concern basis in accordance with the historical cost convention except for non-current listed investments which are measured at market value.

Expenditure commitments include obligations arising from farm-in arrangements, minimum work obligations for the initial three year period of exploration permits and thereafter annually. Minimum work obligations may, subject to negotiation and approval, be varied. They may also be satisfied by farmout, sale, relinquishment or surrender of a permit.

The consolidated entity has limited financial resources and will need to raise additional capital from time to time. Any such fund raisings will be subject to factors beyond the control of the consolidated entity and its directors. When the consolidated entity requires further funding for its programs then it is its intention that the additional

NOTES TO THE FINANCIAL STATEMENTS
30 JUNE 2008

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(c) Going concern (continued)
funds would be raised in a manner deemed most expedient by the Board of Directors at the time, taking into account working capital, exploration results, budgets, sharemarket conditions, capital raising opportunities and the interest of industry in co-participation in the consolidated entity's programs.

It is the consolidated entity's plan that this capital will be raised by any one or a combination of the following manners: placement of shares to excluded offerees, pro-rata issue to shareholders, the exercise of outstanding options, and/or a further issue of shares. Should these methods not be considered to be viable, or in the best interests of shareholders, then it would be the consolidated entity's intention to meet its obligations by either partial sale of its interests or farmout, the latter course of action being part of its overall strategy.

(d) Principles of consolidation
The consolidated financial statements have been prepared by Exoil in accordance with paragraph Aus 9.1 of AASB 127, Consolidated and Separate Financial Statements.

(i) Subsidiaries
Subsidiaries are entities controlled by the company. Control exists when the company has the power, directly or indirectly, to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that presently are exercisable or convertible are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases. Investments in subsidiaries are carried at their cost of acquisition in the company's financial statements.

(ii) Jointly controlled operations and assets
The interest of the company and of the consolidated entity in unincorporated joint ventures and jointly controlled assets are brought to account by recognising in the financial statements the assets it controls, the liabilities that it incurs, the expenses it incurs and its share of income that it earns from the sale of goods or services by the joint venture.

(iii) Transactions eliminated on consolidation
Intragroup balances and any unrealised gains and losses or income and expenses arising from intragroup transactions, are eliminated in preparing the consolidated financial statements.

(e) Taxes

Income Tax
Income taxes are accounted for using the comprehensive balance sheet liability method whereby:
- The tax consequences of recovering (settling) all assets (liabilities) are reflected in the financial statements;
- Current and deferred tax is recognised as income or expense except to the extent that the tax related to equity items or to a business combination;
- A deferred tax asset is recognised to the extent that it is probable that future taxable profit will be available to realise the asset;
- Deferred tax asset and liabilities are measured at the tax rates that are expected to apply to the period where the asset is realised or the liability settled.

Goods and Services Tax (GST)
Revenues, expenses and assets are recognised net of the amount of GST, except where the amount of GST incurred is not recoverable from the taxation authority. In these circumstances, the GST is recognised as part of the cost of acquisition of the asset or as part of the expense.

Receivables and payables are stated with the amount of GST included. The net amount of GST recoverable from, or payable to, the taxation authority is included as a current asset or liability in the balance sheet.

NOTES TO THE FINANCIAL STATEMENTS
30 JUNE 2008

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(e) Taxes (continued)
Cash flows are included in the cash flow statement on a gross basis. The GST components of cash flows arising from investing and financing activities which are recoverable from, or payable to, the ATO are classified as operating cash flows.

(f) Receivables
Trade and other receivables are stated at their amortised cost less impairment losses.

(g) Cash and cash equivalents
Cash and cash equivalents comprise cash balances and at call deposits. Bank overdrafts that are repayable on demand and form an integral part of the company's cash management are included as a component of cash and cash equivalents for the purpose of the cash flow statement.

(h) Payables
Trade and other payables are stated at their amortised cost. Trade payables are non-interest bearing and are normally settled on 60-day terms. Advances fully repaid during the year to director-related parties, Great Missenden Holdings Pty Ltd, National Gas Australia Pty Ltd and Cue Energy Resources Limited incurred interest at a rate of 1% per month.

(i) Property, plant and equipment
Items of property, plant and equipment are stated at cost or deemed cost less accumulated depreciation and impairment losses.

Depreciation is charged to the income statement on a straight line basis over the estimated useful lives of each class of property, plant and equipment. The estimated useful lives in the current and comparative year are as follows:

• Computer equipment	4 years
• Office equipment	4 - 20 years
• Leasehold improvements	10 years

(j) Investments
Financial instruments classified as held for trading are measured at fair value through the profit or loss. All resultant gain or loss is recognised in the current year's profit or loss.

The fair value of financial instruments is their quoted price at the balance date.

(k) Share Capital
Ordinary share capital is recognised at the fair value of the consideration received by the company. Transactions costs arising on the issue of ordinary shares are recognised directly in equity as a reduction of the consideration received.

(l) Impairment
The carrying amounts of the consolidated entity's assets, other than deferred tax are reviewed at each balance date to determine whether there is any indication of impairment. If any such indication exists, the asset's recoverable amount is estimated.

Calculation of recoverable amount
Recoverable amount is the greater of fair value less costs to sell and value in use. It is determined for an individual asset, unless the asset's value in use cannot be estimated to be close to its fair value less costs to sell and it does not generate cash inflows that are largely independent of those from other groups or assets, in which case, the recoverable amount is determined for the class of assets to which the asset belongs.

Reversals of impairment
Impairment losses are reversed when there is an indication that the impairment loss may no longer exist and there has been a change in the estimate used to determine the recoverable amount.

NOTES TO THE FINANCIAL STATEMENTS

30 JUNE 2008

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(l) Impairment (continued)

An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortisation, if no impairment loss had been recognised.

(m) Exploration costs

Exploration and evaluation costs, including the costs of acquiring licences, are capitalised as exploration and evaluation assets on an area of interest basis.

Exploration and evaluation costs are only recognised if the rights of the area of interest are current and either:

(i) the expenditures are expected to be recouped through successful development and exploitation of the area of interest; or

(ii) activities in the area of interest have not at the reporting date, reached a stage which permits a reasonable assessment of the existence or otherwise of economically recoverable reserves and active and significant operations in, or in relation to, the area of interest are continuing.

Exploration and evaluation costs are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

(n) Restoration, rehabilitation and environment expenditure

Restoration, rehabilitation and environmental costs necessitated by exploration and evaluation activities are provided for as part of the cost of those activities. Costs are estimated on the basis of current legal requirements, anticipated technology and future costs that have been discounted to their present value. Estimates of future costs are reassessed at each reporting date.

(o) Revenue

Revenue is recognised to the extent that it is probable that the economic benefits will flow to the entity and the revenue can be reliably measured. Interest income is recognised when control of the right to receive the interest payment is attained.

(p) Accounting estimates and judgements

Management determine the development, selection and disclosure of the company's critical accounting policies and estimates and the application of these policies and estimates. There are no estimates and judgements that are considered to have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year.

There is, however, a risk that actual expenditure to achieve minimum work obligations could differ from estimates disclosed in the notes to the financial statements (see Note 14). The estimated amounts represent the higher end of possible future expenditure. Work requirements achieved by farm-ins materially reduce the level of expenditure incurred by the company to comply with work program commitments.

(q) Fair value

Fair values for financial instruments traded in active markets are based on quoted market prices at balance sheet date. The quoted market price for financial assets is the current bid price and/or the quoted market price.

The fair value of financial instruments that are not traded in an active market are determined using valuation techniques. Assumptions used are based on observable market prices and rates at balance date. Estimated discounted cash flows are used to determine fair value of the remaining financial instruments.

The carrying value less impairment provision of trade receivables and payables are assumed to approximate their fair values due to their short-term nature. The fair value of financial liabilities for disclosure purposes is estimated by discounting the future contractual cash flows at the current market interest rate that is available to the company for similar financial instruments

NOTES TO THE FINANCIAL STATEMENTS
30 JUNE 2008

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(r) New and Revised Accounting Standards
The consolidated entity has adopted all of the new and revised Accounting Standards issued by the Australian Accounting Standards Board (AASB) that are relevant to its operations and effective for annual reporting periods beginning on 1 July 2007. The directors do not believe that new and revised standards issued by AASB that are not yet effective will have any material financial impact on the financial statements.

	NOTE	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
NOTE 2 REVENUE					
Management fees		-	20,905	-	560,905
Interest income		80,152	7,632	79,217	1,680
Recovery of administration costs	17	219,759	278,301	219,759	278,301
Increase on revaluation of investments		-	6,448	-	6,448
Exchange gain		12,607	-	12,607	-
Other Income		-	1,000	-	1,000
		312,518	314,286	311,583	848,334
NOTE 3 OTHER EXPENSES					
Audit fees	4	33,000	29,000	33,000	29,000
Consulting fees		34,176	15,643	34,176	15,643
Directors fees	16	22,500	15,000	22,500	15,000
Management fees		66,098	41,160	66,098	41,160
Other expenses		77,611	15,491	77,611	15,491
Rent		133,631	95,705	133,631	95,705
Impairment of investments		59,224	-	59,224	-
		426,240	211,999	426,240	211,999
NOTE 4 AUDITOR'S REMUNERATION					
Fees for audit of the financial statements (i)		33,000	29,000	33,000	29,000
Fees for tax compliance		2,000	6,000	2,000	6,000
		35,000	35,000	35,000	35,000

(i) Audit fees of $20,000 have been included for the year ended at 30 June 2008 for a one-off audit performed for the ten month period ended 30 April 2008.

NOTES TO THE FINANCIAL STATEMENTS

30 JUNE 2008

	NOTE	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
NOTE 5 INCOME TAX					
Components of income tax benefit (expense)					
Current tax expense					
Current period		-	-	-	-
Adjustment for prior period		-	(473)	-	-
Deferred tax expense					
Origination and reversal of temporary differences		91,634	(73,858)	91,634	(183,050)
Total income tax benefit (expense)		91,634	(74,331)	91,634	(183,050)
(Loss) profit before tax		(152,930)	73,568	(152,651)	611,741
Income tax benefit (expense) using statutory income tax rate of 30% (2007: 30%)		45,879	(22,070)	45,795	(183,552)
Tax effect of:					
Non deductible items		(32)	(308)	(32)	(308)
Non assessable items		3,782	-	3,782	-
Prospectus costs		780	780	780	780
Tax losses recognised of prior periods		41,309	(473)	41,309	-
Deferred tax asset not brought to account		(84)	(52,260)	-	-
Income tax benefit (expense)		91,634	(74,331)	91,634	(183,050)
Estimated potential future income tax benefit arising from tax losses and temporary differences calculated at a rate of 30% not brought to account at balance date as realisation of the benefit is not probable.					
Tax revenue losses carried forward		316,425	200,892	-	-
Less: Deferred tax liability not brought to account for exploration costs capitalised		(264,081)	(148,632)	-	-
Tax capital losses carried forward		360,000	360,000	-	-
		412,344	412,260	-	-

NOTE 6 TRADE AND OTHER RECEIVABLES

	NOTE	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
CURRENT					
Trade receivables		-	6,177	-	6,175
Receivables from director related entities	17	59,500	68,455	59,500	68,455
Receivables from subsidiary		-	-	-	540,000
Other receivables		239,881	30,968	229,640	24,067
		299,381	105,600	289,140	638,697

The carrying amount of all receivables is equal to their fair value as they are short term. None of the receivables are impaired or past due. The maximum credit risk for the company is the gross value of all receivables. All receivables are non-interest bearing.

NOTES TO THE FINANCIAL STATEMENTS
30 JUNE 2008

	NOTE	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $

NOTE 7 EXPLORATION AND EVALUATION ASSETS

	NOTE	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
Exploration costs capitalised at beginning of period		5,102,468	4,342,334	4,607,028	3,978,358
Costs for the period		738,521	760,134	353,690	628,670
Recoupment of costs from farmin (1) & (2)		(2,108,333)	-	(2,108,333)	-
Exploration costs capitalised at end of period	15	3,732,656	5,102,468	2,852,385	4,607,028

(1) On the 3 December 2007 $2,000,000 was received from Stuart Petroleum Limited per the VIC P/53 Grant of Option and Farm-in agreements for the recoupment of exploration costs previously capitalised.

(2) On the 3 April 2008 $108,333 was received from MEO Australia Limited per the WA-359-P Farm-in agreement for the recoupment of exploration costs previously capitalised.

Ultimate recovery of exploration costs carried forward is dependent upon exploration success and/or the company maintaining appropriate funding to support continued exploration activities.

NOTE 8 PROPERTY, PLANT & EQUIPMENT

	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
Office Equipment				
At cost	20,616	18,952	20,616	18,952
Accumulated depreciation	(5,542)	(3,487)	(5,542)	(3,487)
	15,074	15,465	15,074	15,465
Computer Equipment				
At cost	31,268	33,092	31,268	33,092
Accumulated depreciation	(16,224)	(22,167)	(16,224)	(22,167)
	15,044	10,925	15,044	10,925
Leasehold Improvement				
At cost	51,465	-	51,465	-
Accumulated depreciation	(3,550)	-	(3,550)	-
	47,915	-	47,915	-
Total property, plant and equipment	78,033	26,390	78,033	26,390

Reconciliations of each class of property, plant & equipment is set out below:

	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
Office Equipment				
Balance at beginning of period	15,465	14,718	15,465	14,718
Additions	1,664	2,458	1,664	2,458
Depreciation	(2,055)	(1,711)	(2,055)	(1,711)
Balance at end of period	15,074	15,465	15,074	15,465

NOTES TO THE FINANCIAL STATEMENTS
30 JUNE 2008

	NOTE	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
NOTE 8 PROPERTY, PLANT & EQUIPMENT (Continued)					
Computer Equipment					
-Balance at beginning of period		10,925	19,198	10,925	19,198
-Additions		16,586	-	16,586	-
-Write offs		(4,427)	-	(4,427)	-
-Depreciation		(8,040)	(8,273)	(8,040)	(8,273)
-Balance at end of period		15,044	10,925	15,044	10,925
Leasehold Improvement					
-Balance at beginning of period		-	-	-	-
-Additions		51,465	-	51,465	-
-Depreciation		(3,550)	-	(3,550)	-
-Balance at end of period		47,915	-	47,915	-
NOTE 9 OTHER FINANCIAL ASSETS					
Investments in controlled entities[(1)]					
Unlisted shares at cost		-	-	226,250	226,250
Receivable from subsidiary		-	-	817,976	-
		-	-	1,044,226	226,250
Investment held for trading at fair value through the profit or loss					
Listed equities at cost		112,506	120,006	112,506	120,006
Impairment in value		(87,439)	(28,215)	(87,439)	(28,215)
		25,067	91,791	25,067	91,791
Total other financial assets		25,067	91,791	1,069,293	318,041
Listed shares comprise:					
Rocky Mountain Minerals, Inc[(2,3)]		24,933	88,370	24,933	88,370
Moby Oil & Gas Ltd [(2)]		-	3,375	-	3,375
Other		134	46	134	46

(1) *Exoil Limited has provided management services to its 100% wholly owned subsidiary, Hawkestone Oil Pty Ltd ("Hawkestone"), and advanced funds to Hawkestone for its exploration activity. These advances have not been made for a predetermined period. While management's intention is that Hawkestone will settle its debt to Exoil Limited as and when funds become available, there exists no set date as to when this transaction will occur. The investment is valued at original cost. Hawkestone holds an interest in the Browse Joint Venture permits (Note 15). During 2006 the Browse Joint Venture sold 100% of its interest in the WA-341-P permit. Hawkestone's share of proceeds from the sale was $2,936,186. At balance date the carrying value of Hawkestone's interest in the Browse Joint Venture permits was $654,561 (2007: $269,730). Hawkestone is incorporated in Australia and balances on 30 June.*

(2) *Director related entity of Mr EG Albers*

(3) *Exoil has a 2.98% interest (2007:2.98%) in this company which is engaged in the acquisition, development, exploration and operation of natural resource properties. The company has no proven mineral or petroleum reserves.*

Details of market price risk and sensitivity can be found in Note 18.

NOTES TO THE FINANCIAL STATEMENTS

30 JUNE 2008

NOTE 10 TRADE AND OTHER PAYABLES

	NOTE	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
CURRENT					
Trade creditors and accruals		402,050	124,602	399,604	111,022
Director-related entity other payables	17	96,707	141,246	65,226	91,414
Director-related advance	17	-	244,491	-	244,491
Payables by joint ventures		29,676	108,993	29,676	108,994
		528,433	619,332	494,506	555,921
NON CURRENT					
Payable to subsidiary		-	-	-	190,155
		-	-	-	190,155

Trade and other payables are current liabilities of which the fair value is equal to the current carrying amount. Information about the company's exposure to foreign exchange risk in relation to trade payables, including sensitivities to changes in foreign exchange rates, is provided in Note 18.

NOTE 11 DEFERRED TAX LIABILITIES

	Assets 2008 $	Assets 2007 $	Liabilities 2008 $	Liabilities 2007 $	Net 2008 $	Net 2007 $
Consolidated						
Investment revaluations	(26,233)	(8,465)	-	-	(26,233)	(8,465)
Exploration costs	-	-	855,716	1,382,108	855,716	1,382,108
Accrued expenses	(9,600)	(4,200)	-	-	(9,600)	(4,200)
Tax Losses	(246,022)	(703,948)	-	-	(246,022)	(703,948)
	(281,855)	(716,613)	855,716	1,382,108	573,861	665,495
Company						
Investment revaluations	(26,233)	(8,465)	-	-	(26,233)	(8,465)
Exploration costs	-	-	855,716	1,382,108	855,716	1,382,108
Accrued expenses	(9,600)	(4,200)	-	-	(9,600)	(4,200)
Tax Losses	(246,022)	(703,948)	-	-	(246,022)	(703,948)
	(281,855)	(716,613)	855,716	1,382,108	573,861	665,495

NOTES TO THE FINANCIAL STATEMENTS
30 JUNE 2008

NOTE 12 CONTRIBUTED EQUITY

			Consolidated		The Company	
	2008 Shares	**2007 Shares**	**2008 $**	**2007 $**	**2008 $**	**2007 $**
Issued Capital						
Ordinary shares fully paid	50,775,263	50,775,263	2,959,055	2,959,055	2,959,055	2,959,055
Ordinary Shares						
Ordinary shares on issue at 1 July	50,775,263	50,441,250	2,959,055	2,892,252	2,959,055	2,892,252
Options exercised	-	-	-	-	-	-
Shares issued (1)	-	334,013	-	66,803	-	66,803
Ordinary shares on issue at 30 June	50,775,263	50,775,263	2,959,055	2,959,055	2,959,055	2,959,055

(1) On the 31 July 2006 the company issued shares to Mr Geoff Geary in accordance with the Consultancy Services Agreement between Focus on Australia Pty Ltd and the company dated 21 April 2005.

At a general meeting of shareholders held on 3 September 2008 an ordinary resolution was passed subdividing the fully paid issued ordinary shares in the company into two ordinary shares each credited as fully paid up ordinary shares with the effect that the issued capital of the company comprises 101,550,526 ordinary fully paid shares from that date.

The company has unlimited authorised capital with no par value.

Terms and Conditions of Contributed Equity
Ordinary shares confer on the holder the right to receive dividends as declared and, in the event of a winding up of the company, to participate in the proceeds from the sale of all surplus assets in proportion to the number of shares held (irrespective of the amounts paid up). Ordinary shares entitle their holder to one vote, either in person or by proxy, at a meeting of the company.

Options over Unissued Shares
The company has granted options over unissued shares in the company, each option conferring the right to subscribe for one fully paid ordinary share. The options do not confer the right to dividends or to vote at meetings of members. Shares allotted on exercise of the options will rank pari passu in all respects with other fully paid ordinary shares. Each option will entitle the holder to participate in new issues in which shares or other securities are offered to members on the prior exercise of the option.

During the year no options were granted (2007: Nil), or were exercised (2007: Nil) or expired (2007: Nil). At balance date there were a total of 1,850,000 options over unissued shares outstanding with an expiry date of 31 December, 2009. 1,175,000 of the options are exercisable at 30 cents per share and 675,000 are exercisable at 40 cents per share.

As per above on 3 September 2008 the numbers of options issued were doubled and option prices halved as part of the share sub-division approved by shareholders at that date.

NOTES TO THE FINANCIAL STATEMENTS
30 JUNE 2008

NOTE 13 OPTION RESERVE
An option reserve was established to hold the value of options granted as remuneration to directors and executives of the Company. This treatment is in line with AIFRS requirements for share based payments to be recognised in the income statement when made.

NOTE 14 COMMITMENTS

	NOTE	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
Estimated joint venture work program commitments					
Payable not later than one year		12,607,500	12,332,500	1,512,500	1,745,000
Payable after one year and before three years		4,890,000	8,330,000	4,890,000	8,330,000
		17,497,500	20,662,500	6,402,500	10,075,000

Exploration commitments may, with approval, be deferred or varied, or avoided by sale, farmout or relinquishment of permit interests.

Office lease commitments				
Payable not later than one year	161,687	105,334	161,687	105,334
Payable after one year and before five years	580,250	741,936	580,250	741,936
	741,937	847,270	741,937	847,270

NOTE 15 INTEREST IN JOINT VENTURES
The consolidated entity has an interest in the assets, liabilities and output of joint venture operations for the exploration and development of petroleum in Australia. The consolidated entity has taken up its share of joint venture transactions based on the consolidated entity's contributions to the joint ventures. Expenditure commitments in respect of the joint ventures are disclosed in Note 14. Details of the consolidated entity's interests in the joint ventures are:

Joint Venture	Note	Interest 2008	Interest 2007	Permits Held
Browse Basin (i)	17	35%	35%	WA-332-P, WA-333-P & WA-342-P
T/37P & T/38P (ii) (iii)	17	35%	50%	
Vic/P45(iv)	17	50%	16.7%	
Vic/P53	17	16.7%	50%	
Vic/P61	17	30%	30%	
WA-359-P	17	20%	50%	
Western Otway Joint Venture (v)	17	15%	25%	EPP34
EPP35(vi)	17	30%	30%	
EPP36(vii)	17	30%	30%	

(i) Gascorp Australia Pty Ltd ("Gascorp") has committed to a farmin obligation per a farmin agreement effective 30 June 2008 (Note 20). When the work has been performed the consolidated entity's interest in all three permits will be 29.75%
(ii)A defined portion of the T/38P permit was farmed out to Beach Petroleum on 1 October 2007.
(iii)Gascorp farmed into both permits in June 2008.
(iv)Apache Northwest Pty Ltd relinquished its interest in the Vic/P45 permit on 15 May 2008.
(v) In June 2008 Gascorp farmed into this permit.

NOTES TO THE FINANCIAL STATEMENTS
30 JUNE 2008

NOTE 15 INTEREST IN JOINT VENTURES (Continued)

(vi) EPP35 Farmin
Exoil signed a farm-out agreement with Gascorp, effective 30 June 2008, in relation to EPP35. In return for Gascorp funding seismic survey costs for EPP35 Exoil has agreed to farm-out a 10% interest in the permit.

Whilst Gascorp has committed to the farmin obligation as at 30 June 2008, the farmin work has not been performed or the funds outlayed as at the date of signing this report. When the seismic program is complete Exoil's interest in the permit will be 20%.

(vii) EPP36 Farmin
Exoil signed a farm-out agreement with Gascorp, effective 30 June 2008, in relation to EPP36. In return for Gascorp funding seismic survey costs for EPP36 Exoil has agreed to farm-out a 10% interest in the permit.

Whilst Gascorp has committed to the farmin obligation as at 30 June 2008, the farmin work has not been performed or the funds outlayed as at the date of signing this report. When the seismic program is complete Exoil's interest in the permit will be 20%.

Assets and liabilities of the joint venture operations are included in the financial statements as follows:

		Consolidated		The Company	
	NOTE	**2008**	**2007**	**2008**	**2007**
		$	**$**	**$**	**$**
CURRENT ASSETS					
Cash assets (1)		187,102	96,347	190,858	60,262
Trade & other receivables		231,225	25,242	221,981	17,384
NON-CURRENT ASSETS					
Exploration and evaluation assets	7	3,732,656	5,102,468	2,852,385	4,607,028
Other financial assets		-	3,375	-	3,375
CURRENT LIABILITIES					
Trade & other payables		400,271	215,918	366,793	156,632

(i) The Browse Joint Venture has no overdraft facility. The account was temporarily allowed to be in a credit balance by the Joint Venture Operator's bank until funded by Joint Venture partners on 17 July 2008. That is why Consolidated Cash assets are lower than company cash assets by $3,756.

NOTE 16 KEY MANAGEMENT PERSONNEL

Key management personnel disclosures

Non-executive Directors
PJ Albers
GA Menzies
JMD Willis

Executive Director
EG Albers

Executive
M Muzzin

Key management personnel remuneration
The Board of directors is responsible for determining and reviewing compensation arrangements for key management personnel.

Remuneration for key management personnel for the year ended 30 June 2008 was $22,500 (2007: $15,000).

NOTES TO THE FINANCIAL STATEMENTS
30 JUNE 2008

NOTE 16 KEY MANAGEMENT PERSONNEL (Continued)

Ordinary shares issued by Exoil Limited to Key Management Personnel

	Opening Balance	Received as Remuneration	Options Exercised	Other	Closing Balance
2008					
JMD Willis	1,156,250	-	-	-	1,156,250
EG Albers *	40,059,992	-	-	-	40,059,992
PJ Albers *	40,059,992	-	-	-	40,059,992
MA Muzzin	1,556,250	-	-	-	1,556,250
2007					
JMD Willis	1,156,250	-	-	-	1,156,250
EG Albers *	40,059,992	-	-	-	40,059,992
PJ Albers *	40,059,992	-	-	-	40,059,992
MA Muzzin	1,556,250	-	-	-	1,556,250

* Ordinary shares in which more than one director holds an interest.

No shares were granted to key management personnel during the reporting year as compensation. Per Note 12, the number of shares held by each person in the table above for 2008 doubled on 3 September 2008.

Options (exercisable by 31 December 2009 at 30-40 cents per share)

	Opening Balance	Options Granted	Options Expired	Closing Balance
2008				
JMD Willis	200,000	-	-	200,000
EG Albers	100,000	-	-	100,000
PJ Albers	100,000	-	-	100,000
GA Menzies	200,000	-	-	200,000
MA Muzzin	375,000	-	-	375,000
	975,000	-	-	975,000
2007				
JMD Willis	200,000	-	-	200,000
EG Albers	100,000	-	-	100,000
PJ Albers	100,000	-	-	100,000
GA Menzies	200,000	-	-	200,000
MA Muzzin	375,000	-	-	375,000
	975,000	-	-	975,000

No options exercisable by 31 December 2009 were exercised in the year ended 30 June 2007 or the year ended 30 June 2008. Per Note 12, the number of options held by each person in the table above for 2008 doubled on 3 September 2008 and option exercise prices halved.

NOTES TO THE FINANCIAL STATEMENTS
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NOTE 17 RELATED PARTY DISCLOSURES

Ultimate Parent
Great Australia Corporation Pty Ltd is the immediate parent company and its ultimate parent company is Seaquest Petroleum Pty Ltd.

Director-related Entities
Companies in which an Exoil director holds office, or that a director holds shares in that company, or that provide services to the company, or that the company provides services to, or to a joint venture in which the company has an interest or that also hold an interest in those joint ventures.

(i)Providers of Services
During the period services were provided under normal commercial terms and conditions by:

Capricorn Mining Pty Ltd, ("Capricorn"), a director-related entity of EG Albers
Great Missenden Holdings Pty Ltd ("GMH"), a director-related entity of EG Albers and PJ Albers
Setright Oil & Gas Pty Ltd, ("Setright"), a director-related entity of EG Albers and PJ Albers
Upstream Consulting Pty Ltd ("Upstream"), a director-related entity of JMD Willis
National Gas Australia Pty Ltd ("NGA"), a director-related entity of EG Albers and PJ Albers

Company	**Service Provided**	**2008 $**	**2007 $**
Capricorn	Management of exploration tenements	96,111	48,835
Capricorn	Corporate management and administration	12,000	-
GMH	Provision of geological equipment for joint ventures in WA	-	12,600
Setright	Accounting, project management and company secretarial services	48,730	41,160
Setright	Accounting, project management of joint ventures	23,247	32,951
Upstream	Management and consulting services to the company	17,200	8,000
Upstream	Management and consulting to joint ventures	45,523	14,900
NGA	Provision of office services to joint venture in WA	37,063	-

(ii)Advance of funds
During 2008 funds advanced to the company were repaid in full to:

NGA, a director-related entity of EG Albers and PJ Albers
GMH, a director-related entity of EG Albers and PJ Albers
Cue Energy Resources Limited ("Cue"), a director-related entity of EG Albers

Interest paid / accrued on advances for the year at an interest rate of 1% per month

	2008 $	**2007 $**
GMH	8,689	8,625
NGA	4,273	5,066
Cue	11,384	-

NOTE 17 RELATED PARTY DISCLOSURES (Continued)
(iii) Services Provider

During the year office services and amenities were provided by the company under normal commercial terms and conditions to:
Moby Oil & Gas Ltd, ("Moby"), a director-related entity of EG Albers and GA Menzies
Capricorn, a director-related entity of EG Albers
Octanex N.L., ("Octanex"), a director-related entity of EG Albers, P J Albers and GA Menzies
Strata Resources NL, ("Strata"), a director-related entity of EG Albers, P J Albers and GA Menzies
Auralandia NL, ("Auralandia"), a director-related entity of EG Albers and PJ Albers
NGA, a director-related entity of EG Albers and PJ Albers
Setright, a director-related entity of EG Albers and P J Albers
RMMI Australia Pty Ltd ("RMMI"), a director-related entity of EG Albers
Goldsborough Limited ("Goldsborough"), a director-related entity of EG Albers

Company	**2008 $**	**2007 $**
Moby	25,584	29,804
Capricorn	32,318	37,255
Octanex	38,781	53,642
Strata	6,463	8,940
Auralandia	19,391	26,821
NGA	38,781	53,642
Setright	38,781	53,642
RMMI	12,927	5,615
Goldsborough	6,463	8,940
Total	219,489	278,301

(iv) Joint Venture Participants
The company holds interests in petroleum exploration joint ventures with certain director-related entities:

- As a participant of the Bass Basin Joint Venture (T37/P and T/38P) with operator Cue Energy Resources Ltd ("Cue"), a director-related entity of EG Albers.
- As operator of the Browse Basin Joint Venture with Batavia Oil & Gas Pty Ltd, Alpha Oil and Gas Pty Ltd and Goldsborough Energy Pty Ltd, all director-related entities of EG Albers.
- The participants with Exoil Ltd in the Western Otway Joint Venture, National Energy Pty Ltd, a director-related entity of EG Albers, and United Oil and Gas Pty Ltd and Moby both director-related entities of EG Albers and GA Menzies.
- As a participant of the Vic/P45 Joint Venture with Moby, a director-related entity of EG Albers and GA Menzies.
- As the operator of the Vic/P53 Joint Venture with Cue a director-related entity of EG Albers and Moby a director-related entity of EG Albers and GA Menzies
- As the operator of the Vic/P61 Joint Venture with Gascorp Australia Pty Ltd ("Gascorp"), Otway Oil and Gas Pty Ltd and Southern Energy, all director-related entities of EG Albers. GA Menzies and JMD Willis are also directors of Gascorp.
- As a participant of the WA359P with operator Cue a director-related entity of EG Albers.
- As the operator of both the EPP35 and EPP36 joint ventures with Moby, Gascorp and National Energy Pty Ltd all director related entities of EG Albers. GA Menzies and JMD Willis are also directors of Gascorp.

NOTES TO THE FINANCIAL STATEMENTS
30 JUNE 2008

NOTE 17 RELATED PARTY DISCLOSURES (Continued)

(v) Investments in Director-related Companies
In 2007 the company held investments in Moby of which Directors EG Albers and GA Menzies are directors and shareholders (Note 9). This investment was sold during the year.

Amounts payable by and payable to related parties including those under joint venture arrangements:

	NOTE	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
Receivables:					
Moby Oil & Gas Limited		5,908	12,605	5,908	12,605
National Energy Pty Ltd		-	6,888	-	6,888
Otway Oil and Gas Limited		-	7,275	-	7,275
Southern Energy Pty Ltd		-	7,282	-	7,282
Auralandia NL		4,026	4,915	4,026	4,915
Natural Gas Australia Pty Ltd		8,051	9,830	8,051	9,830
Octanex N.L.		8,051	9,830	8,051	9,830
Strata Resources NL		3,142	1,638	3,142	1,638
Capricorn Mining Pty Ltd		6,708	8,192	6,708	8,192
RMMI Australia Pty Ltd		14,220	-	14,220	-
Goldsborough Limited		1,342	-	1,342	-
Setright Oil & Gas Pty Ltd		8,052	-	8,052	-
		59,500	68,455	59,500	68,455
Payables					
Batavia Oil & Gas Pty Ltd		-	5,021	-	5,021
Great Missenden Holdings Pty Ltd		-	34,500	-	6,930
Setright Oil & Gas Pty Ltd		10,910	22,451	10,475	22,248
Goldsborough Energy Pty Ltd		-	1,434	-	1,434
Upstream Consulting Pty Ltd		14,010	12,195	12,624	12,041
Capricorn Mining Pty Ltd		57,287	65,645	42,127	43,740
National Gas Australia Pty Ltd		14,500	-	-	-
		96,707	141,246	65,226	91,414
Interest bearing advance					
Great Missenden Holdings Pty Ltd		-	163,625	-	163,625
National Gas Australia Pty Ltd		-	80,866	-	80,866
		-	244,491	-	244,491

NOTE 18 FINANCIAL INSTRUMENTS

Categories of Financial Instruments

	NOTE	Consolidated 2008 $	Consolidated 2007 $	The Company 2008 $	The Company 2007 $
Financial Assets					
Investments held for trading at fair value through the profit or loss	9	25,067	91,791	25,067	91,791
Loans and receivables (including cash and cash equivalents)		1,270,368	219,344	1,263,883	716,356
		1,295,435	311,135	1,288,950	808,147
Financial Liabilities					
Amortised Cost	10	528,433	619,332	494,506	555,921

Recognition and derecognition

The regular way purchases and sales of financial assets and financial liabilities are recognised on trade date is the date on which the consolidated entity commits to purchase or sell the financial assets or financial liabilities. Financial assets are derecognised when the rights to receive cash flows from the financial assets have expired or have been transferred and the group has transferred substantially all the risks and rewards of ownership.

Exposure to credit, liquidity, interest rate, foreign currency and equity price risks arises in the normal course of the consolidated entity's business. The consolidated entity's overall risk management approach is to identify the risks and implement safeguards which seek to minimise potential adverse effects on the financial performance of the consolidated entity's business. The board of directors are responsible for monitoring and managing the financial risks of the consolidated entity.

Credit risk

Credit risk is the risk of financial loss to the company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. At the balance sheet date there were no significant concentrations of credit risk as the consolidated entity has no trade sales or trade receivables. The maximum exposure to credit risk of financial assets is represented by the carrying amounts of each financial asset in the balance sheet.

Liquidity risk

Liquidity risk is the risk that the group will not be able to meet its financial obligations as they fall due. Liquidity risk is monitored to ensure sufficient monies are available to meet contractual obligations as and when they fall due.

Interest rate risk

All financial liabilities and financial assets at floating rates expose the consolidated entity to cash flow interest rate risk the consolidated entity has no exposure to interest rate risk at balance date, other than in relation to cash and cash equivalents which attract an interest rate.

Sensitivity Analysis

At balance date a 1% (100 basis point) increase/decrease in the interest rate would increase/decrease the consolidated entity post tax profit and net assets by $6,811 (2007: $810) and for the company by $6,837 (2007: $558).

NOTES TO THE FINANCIAL STATEMENTS
30 JUNE 2008

NOTE 18 FINANCIAL INSTRUMENTS (Continued)

Foreign currency risk

The consolidated entity is exposed to foreign currency risk arising from purchases of goods and services that are denominated in a currency other than the Australian dollar functional currency. The consolidated entity incurs seismic, exploration and well drillings costs in US dollars. To this extent, the consolidated entity is exposed to exchange rate fluctuations between the Australian and US dollar. Through its interest in the Western Otway Joint Venture the consolidated entity had an exposure to a US dollar payable of US$263,143 at 30 June 2008.

There was no material exposure to foreign currency in 2007.

Sensitivity Analysis

If the Australian dollar strengthened /weakened by 10% against the US dollar with all other variables held constant, the payable for the company and consolidated entity would have been A$24,852 lower / A$27,337 higher. The company's exposure was settled since balance date for A$279,529.

Equity price risks

Equity price risk arises from available for sale investments held by the parent and consolidated entity in the form of investments in listed equities. The portfolio of investments is managed internally by Exoil management who buy and sell equities based on their own analyses of returns.

Available for sale investments in listed equities of $25,067 (2007: $91,791) for the consolidated entity and the parent entity are subject to movements in prices of the investment markets.

The consolidated entity and company investments in listed equities are listed on the Australian Stock Exchange and in the United States on the Over-the Counter Bulletin Board (OTC-BB). A 10% (2007: 10%) increase / decrease at the reporting date in closing share price of each share held would have increased/decreased consolidated equity by $2,507 (2007: $9,179). There would have been no effect on profit.

Capital Management

When managing capital, management's objective is to ensure the entity continues as a going concern as well as to maintain optimal returns to shareholders and benefits for other stakeholders.

It is the company's and consolidated entity's plan that capital will be raised by any one or a combination of the following manners: placement of shares to excluded offerees, pro-rata issue to shareholders, the exercise of outstanding options, and/or a further issue of shares. Should these methods not be considered to be viable, or in the best interests of shareholders, then it would be the consolidated entity's intention to meet its exploration obligations by either partial sale of its interests or farmout, the latter course of action being part of its overall strategy.

The company and consolidated entity are not subject to any externally imposed capital requirements.

NOTE 19 SEGMENT INFORMATION

The economic entity operates in Australia in the petroleum exploration industry.

NOTES TO THE FINANCIAL STATEMENTS
30 JUNE 2008

NOTE 20 CONTINGENT ASSETS AND LIABILITIES

Vic/P53 Farmin
In accordance with the Vic/P53 farmin agreement dated 17 August 2007, Stuart Petroleum Limited ('Stuart') was obliged to pay an aggregate amount of US$1,150,000 to Exoil (US$766,667) and Moby Oil & Gas Limited (US$383,333), not later than ten days prior to the spudding of the first well in the permit, to meet the obligation of Moby and Exoil to Cue Petroleum Pty Ltd ("Cue') for those amounts, incurred when Moby and Exoil acquired an interest in the permit. These funds were received from Stuart and forwarded to Cue during September 2008.

T/37P Farmin
On 29 April 2008, Exoil entered into a Call Option Agreement and a Put Option Agreement with Gascorp Australia Pty Ltd ("Gascorp") relating to the 15% interest in T/37P acquired by Gascorp under the farmin agreement signed the same day. Under the Call Option Agreement, Exoil can call upon Gascorp to reassign the 15% interest in T/37P to Exoil. The consideration payable, if the Call Option is exercised, is the agreement of Exoil to repay to Gascorp the sum of $1,663,000 paid under the relevant farmin agreement, plus interest at 0.75% per month, together with the grant of a 1% overriding royalty on the 15% interest to be reassigned. Under the Put Option Agreement, Gascorp can require Exoil to take a reassignment of the 15% interest. If the put option is exercised by Gascorp, Exoil must repay $1,663,000 to Gascorp plus interest at 0.75% per month and grant Gascorp a 1% overriding royalty on the 15% interest so reassigned.

T/38P Farmin
On 29 April 2008, Exoil entered into a Call Option Agreement and a Put Option Agreement with Gascorp relating to the 15% interest in T/38P acquired by Gascorp under the farmin agreement signed the same day. Under the Call Option Agreement, Exoil can call upon Gascorp to reassign the 15% interest in T/38P to Exoil. The consideration payable, if the Call Option is exercised, is the agreement of Exoil to repay to Gascorp the sum of $453,000 paid under the relevant farmin agreement, plus interest at 0.75% per month, together with the grant of a 1% overriding royalty on the 15% interest to be reassigned. Under the Put Option Agreement, Gascorp can require Exoil to take a reassignment of the 15% interest. If the put option is exercised by Gascorp, Exoil must repay $453,000 to Gascorp plus interest at 0.75% per month and grant Gascorp a 1% overriding royalty on the 15% interest so reassigned.

EPP34 Farmin
On 29 April 2008, Exoil entered into a Call Option Agreement and a Put Option Agreement with Gascorp relating to the 10% interest in EPP 34 acquired by Gascorp under the farmin agreement signed the same day. Under the Call Option Agreement, Exoil can call upon Gascorp to reassign the 10% interest in EPP 34 to Exoil. The consideration payable, if the Call Option is exercised, is the agreement of Exoil to repay to Gascorp the sum of $525,000 paid under the relevant farmin agreement, plus interest at 0.75% per month, together with the grant of a 1% overriding royalty on the 10% interest to be reassigned. Under the Put Option Agreement, Gascorp can require Exoil to take a reassignment of the 10% interest. If the put option is exercised by Gascorp, Exoil must repay $525,000 to Gascorp plus interest at 0.75% per month and grant Gascorp a 1% overriding royalty on the 10% interest so reassigned.

Browse Joint Venture Permits Farmin
Hawkestone Oil Pty Ltd ("Hawkestone'), the fully owned subsidiary of Exoil, along with other participants in the Browse Joint Venture, signed a farm-out agreement with Gascorp, effective 30 June 2008, in relation to all three of the Browse Joint Venture permits. In return for Gascorp funding seismic survey costs for WA-332-P and WA-333-P Exoil has agreed to farm-out a 5.25% interest the three Browse Joint Venture permits.

Whilst Gascorp Australia Pty Ltd has committed to the farmin obligation as at the 30 June 2008 , the farmin work has not been performed or the funds been outlayed as at the date of signing this report.

Hawkestone, and the other Browse Joint Venture participants, entered into a Put Option Agreement, effective 30 June 2008, with Gascorp relating to the 5.25% interests to be acquired by Gascorp under the farmin agreement. Under the Put Option Agreement, Gascorp can require Hawkestone to take a reassignment of the 5.25% interests. If the put option is exercised by Gascorp, Hawkestone must repay its pre-farmin share of $1,200,000 to Gascorp plus interest at 0.75% per month.

NOTES TO THE FINANCIAL STATEMENTS
30 JUNE 2008

NOTE 20 CONTINGENT ASSETS AND LIABILITIES(Continued)

Gascorp Put Option Agreements
In relation to the above Put Option agreements between Gascorp and Exoil, Gascorp has stated that "the put options will only be exercised if Exoil is in a working capital position where it is capable of repaying the relevant sum without having a significant negative impact on such working capital or the going concern status of Exoil. In the event that Exoil was in such a disadvantaged position, then Exoil can elect that the term of the Put Option be extended for a further period of 15 months. If at the end of such further period of 15 months that Exoil was again not then in a position to repay the relevant sum without having negative impact on the working capital or going concern status of Exoil, then the Put Option would lapse.

However, nothing herein shall disqualify Gascorp from simultaneously exercising any of the Put Option agreements and subscribing new share capital to Exoil Limited for an amount not less than the value of the Put Option and any increments of interest due upon its exercise.

Furthermore, nothing herein shall disqualify Gascorp from accepting any other form of consideration offered by Exoil (such as other tenements or other non-cash interests) upon exercise of the Put Option agreements, provided that, accepting such consideration would not jeopardise the capital position or going concern basis of Exoil."

Rental Bank Guarantee
A contingent liability exists in the form of a rental bank guarantee for $43,450.

NOTE 21 EVENTS SUBSEQUENT TO BALANCE DATE

At a general meeting of shareholders held on 3 September 2008 an ordinary resolution was passed subdividing the fully paid issued ordinary shares in the company into two ordinary shares each credited as fully paid up ordinary shares with the effect that the issued capital of the company comprises 101,550,526 ordinary fully paid shares from that date. The share sub-division also impacted Options. The numbers of option issued were doubled and option prices halved, also on 3 September 2008.

On 18 September 2008 Stuart Petroleum Limited, as operator of the Vic/P53 Joint Venture, announced that the Bazzard-1 well would commence drilling on or about 19 September 2008. The well was completed on 8 October 2008, when it was plugged and abandoned.

NOTE 22 CASH AND CASH EQUIVALENTS
The Browse Joint Venture, in which the interest is held by the subsidiary of Exoil, Hawkestone, has no bank overdraft facility. The bank account for the Joint Venture was temporarily allowed to be in a credit balance by the Joint Venture Operator's bank until funded by Joint Venture partners on 17 July 2008. Consequently, consolidated entity cash assets are lower than company cash assets by $3,756 at 30 June 2008.

PKF
Chartered Accountants
& Business Advisers

**AUDITOR'S INDEPENDENCE DECLARATION
TO THE DIRECTORS OF EXOIL LIMITED**

As lead auditor for the audit of Exoil Limited for the year ended 30 June 2008, I declare that, to the best of my knowledge and belief, there have been:

(a) no contraventions of the auditor independence requirements of the Corporations Act 2001 in relation to the audit; and

(b) no contraventions of any applicable code of professional conduct in relation to the audit.

This declaration is in respect of Exoil Limited and the entity it controlled during the year.

PKF

PKF
East Coast Practice

M L Port
Partner

29 October 2008
Melbourne

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INDEPENDENT AUDITOR'S REPORT
TO THE MEMBERS OF EXOIL LIMITED

We have audited the accompanying financial report of Exoil Limited ("the company") and the consolidated entity for the year ended 30 June 2008. The financial report comprises the balance sheet as at 30 June 2008, and the income statement, statement of changes in equity and cash flow statement for the year ended on that date, a summary of significant accounting policies and other explanatory notes and the directors' declaration of the consolidated entity for both the company and the entities it controlled at the year's end or from time to time during the financial year.

Directors' Responsibility for the Financial Report

The directors of the company are responsible for the preparation and fair presentation of the financial report in accordance with Australian Accounting Standards (including the Australian Accounting Interpretations) and the *Corporations Act 2001*. This responsibility includes establishing and maintaining internal controls relevant to the preparation and fair presentation of the financial report that is free from material misstatement, whether due to fraud or error; selecting and applying appropriate accounting policies; and making accounting estimates that are reasonable in the circumstances. In Note 1(a), the directors also state, in accordance with Accounting Standard AASB 101 "Presentation of Financial Statements", that the financial report, comprising the financial statements and notes, complies with International Financial Reporting Standards.

Auditor's Responsibility

Our responsibility is to express an opinion on the financial report based on our audit. We conducted our audit in accordance with Australian Auditing Standards. These Auditing Standards require that we comply with relevant ethical requirements relating to audit engagements and plan and perform the audit to obtain reasonable assurance whether the financial report is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial report. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the financial report, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial report in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by the directors, as well as evaluating the overall presentation of the financial report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Independence

In conducting our audit, we have complied with the independence requirements of the *Corporations Act 2001*.

Auditor's Opinion

In our opinion:

(a) the financial report of Exoil Limited is in accordance with the *Corporations Act 2001*, including

  (i) giving a true and fair view of the financial position of the company and the consolidated entity as at 30 June 2008 and of their performance for the year ended on that date; and

  (ii) complying with Australian Accounting Standards (including the Australian Accounting Interpretations) and the *Corporations Regulations 2001*; and

(b) the financial report also complies with International Financial Reporting Standards as disclosed in Note 1(a).

PKF

PKF
East Coast Practice

M L Port
Partner

29 October 2008
Melbourne

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SECTION 10: GENERAL MATTERS

Set out in this Section are details of material agreements and additional information which is provided for the information of Proposing Investors generally.

10.1 MATERIAL AGREEMENTS

The Company has not entered into any material agreements other than in the ordinary course of its business. Material contracts which remain uncompleted or which continue to be relevant to investment in the Company are described below. Following is a summary of those agreements.

10.1.1 Exploration Permits: General Terms

Each of the Permits has been granted under the *Petroleum (Submerged Lands) Ac*t (now the "*Offshore Petroleum Act 2006*") by the Designated Authority for an initial six year period. The relevant dates of each Permit and their individual work obligations are more specifically set out in Section 12.

Generally each of the Permits provides rights to the holder to undertake exploration, including seismic surveys and drilling, in the defined area of the Permit.

Under the terms of each Permit the exploration work program nominated for the first three years must be met. The Permit holder may withdraw from any Permit after the third permit year, or at the end of any subsequent permit year, providing all the exploration work obligations up to the date of withdrawal have been met.

The Permits may be renewed for two subsequent five year periods, providing they are in good standing at the end of each preceding period and provided half of the remaining area of the Permit is relinquished on each renewal. Any production licence, retention lease or location graticules are excluded from the relinquishment calculation.

The holders of a Permit may not construct any installation in the Permit or abandon, suspend or complete any well without the written approval of the Designated Authority.

A Permit requires the holders to comply with the *Offshore Petroleum Act 2006*, Regulations made pursuant to that Act and, as stipulated by the relevant Designated Authority, all directions made thereunder and to carry out operations with adequate measures for the protection of the environment and to carry insurance.

Details of all current and proposed work programs are set out in Section 4.

10.1.2 Operating Agreements

The Company has entered into separate Joint Operating Agreements ("JOA") in relation to each of the Permits in which it has an interest and is Operator under various of the JOA's, as set out in Section 4.

The JOA's follow a comparatively uniform format as detailed below. Exceptions are minor and normally project specific. Where material differences occur they are referred to below in context.

Conduct of Joint Operations

Under each JOA, the Operator is responsible for the conduct of joint operations.

The Operator may resign as operator on giving appropriate notice but is entitled to continue as operator in normal business circumstances.

Insurance

The Operator will, to the best of its ability, procure and maintain for the joint venture statutory insurances and other insurances required by the operating committee, with any other joint venturer having the right not to participate in non-statutory insurances.

Operating Committee

A joint venturer has the right to appoint one representative to serve on the operating committee which has the power and duty to authorise and supervise joint operations. Each representative has a vote equal to its participating interest. Generally a 66% affirmative vote by at least two joint venture participants (not being affiliates of one another) is required to pass a resolution. If there are four or more joint venturer, a 70% affirmation vote is required from at least two non-affiliated participants.

Some of the more important decisions require unanimity.

The operating committee considers exploration work programs and targets that are to be presented by the Operator up to nine months (in a preliminary way) and up to three months (in final form) before the commencement of each permit year.

The operating committee meets following delivery of the final proposed work program and budget to agree a work program and budget for the ensuing year.

Once a development plan for a commercial discovery is approved, the Operator then submits development and production plans and budgets to the operating committee in advance of the commencement of the next calendar year.

Authorisation for Expenditure

Before incurring any expenditure, whether for exploration, appraisal, development or production, the Operator submits an authorisation for expenditure to each joint venturer. Each authorisation must be approved by the operating committee prior to expenditure being committed to or undertaken.

Sole Risk

Where the operating committee does not approve a proposed exploration or appraisal well, a party may undertake the project as a sole risk project with the right of the non-participants to buy back in at various premiums which differ between the cases of a development well, an appraisal well and an exploration well. The premium to buyback can normally be paid in kind (out of petroleum produced) or in cash.

Default

A joint venturer that fails to pay when due its share of joint venture expenditure is a defaulting party. A defaulting party is not entitled to attend operating committee meetings or to vote. The sum of money in default is allocated to and paid by the non-defaulting parties pro rata to their participating interests. Reasonable opportunity to cure a default is given to a defaulting party.

For a specified period following a notice of default which has not been cured, the JOA states that each non-defaulting party shall have the option to give notice to the defaulting party to transfer its entire interest to the non-defaulting parties.

Assignments

A joint venturer may assign all or part of its joint venture interest to an affiliate, but generally assignments to non-affiliates will attract pre-emptive rights provisions. Permit WA 359-P does not have pre-emptive rights provisions. In all cases the assignee must be accepted by the remaining joint venturers as being financially capable of meeting all obligations assumed under the relevant permit and the relevant JOA.

Cross Charge

If the operating committee decides to develop a discovery, the parties are required to charge their joint venture interests and shares of petroleum produced in favour of one another in order to secure the performance of their respective obligations under the relevant JOA. In the same way, where any joint venturer seeks to encumber its participating interest, the party proposing to encumber its interest in favour of a third party must grant such prior ranking cross charges to which the charge in favour of the third party will be subject.

Withdrawal

Subject to certain conditions for the protection of the other party or parties to the relevant joint venture, a party which is unwilling to commit further to expenditure on a permit may withdraw from the relevant joint venture. Once development of a discovery has commenced, those conditions include a condition that other parties be willing to accept the withdrawing party's interest.

10.1.3 Farmin Agreement between Exoil and Cue Petroleum with respect to Vic/P53

On 10 December 2004, Cue Petroleum Pty Ltd (Cue Petroleum) entered into a farmin agreement with Exoil pursuant to which Cue Petroleum agreed to assign a 50% interest in Vic/P53 to Exoil in consideration for the agreement of Exoil to meet 66.667% of the costs of the Bazzard 3D seismic programme, 66.667% of the costs of the first well (Bazzard-1) in the Permit and 60% of the costs of the second well. Exoil also agreed that the 50% interest assigned to it is encumbered with a pro-rata share of a pre-existing 4% overriding royalty obligation in favour of Australian Crude Oil Company ("ACOC"). This overriding royalty was created via a farmin agreement between Cue Petroleum and ACOC, pursuant to which Cue Petroleum acquired its rights in respect to Vic/P53.

Following the drilling of Bazzard-1, Exoil has the right to elect not to proceed with the next well in the Permit and must reassign a 50% interest in the Permit to Cue Petroleum.

10.1.4 Farmin Agreement between Exoil and Stuart with respect to Vic/P53

On 17 August 2007, Exoil, Cue Petroleum and Moby Oil & Gas Ltd ("Moby") entered into a farmin agreement with Stuart Petroleum (Offshore) Limited ("Stuart") pursuant to which Exoil agreed to assign to Stuart a 33.333% interest in Vic/P53 in consideration for the agreement of Stuart:

(i) to pay US$1,333,333 to Exoil;

(ii) to pay a further US$766,667 to Exoil not later than 10 days prior to the spudding of the first well in the Permit;

(iii) to meet all of the costs of the first well in the Permit;

(iv) to meet all of the costs of a second well in the Permit unless Stuart elects to reassign; and

(v) meet all other costs related to ongoing permit activities until the cessation of drilling operations for the second well.

Stuart has drilled Bazzard 1 as the first well of the 2 wells referred to above and now has the right to re-assign its interest in the Permit to Exoil. At this stage Stuart has not advised the Company of its intention. If Stuart re-assign its interest in the Permit Exoil's interest will be 33.3334%. If Stuart elects to drill the second well Stuart will be entitled to retain a 50% interest in the permit and in any Retention Lease or Production Licence which may be applied for in relation to any discovery area which may be excised in the event of a discovery being made by the second well.. As a result of this farmin agreement the participating interests in Vic/P53 are now:

Stuart	50%
Cue Petroleum	25%
Exoil	16.667%
Moby	8.833%

10.1.5 Farmin Agreement between Exoil and Apache with respect to Vic/P45

On 29 March 2006, Exoil and Moby entered into a farmin agreement with Apache Northwest Pty Ltd ("Apache") pursuant to which Exoil assigned to Apache a 33.3334% interest in Vic/P45 in consideration of Apache meeting the costs of up to two wells in the Permit. Apache met all the costs of Coelacanth-1, drilled in the Permit in March 2008. Following that well, Apache exercised its right under the farmin agreement to reassign the Permit interests acquired from each of Exoil and Moby. Documentation to effect this reassignment is now being prepared for execution by all parties, after which the participating interests in Vic/P45 will be:

Exoil	50%
Moby	50%

10.1.6 Farmin Agreement between Exoil and Gascorp with respect to T/37P

On 29 April 2008, Exoil entered into a farmin agreement with Gascorp Australia Pty Ltd ("Gascorp") pursuant to which Gascorp agreed to meet the first $1,663,000 of Exoil's share of the costs of the 2D seismic programme recently completed in T/37P. As consideration, Exoil agreed to assign a 15% interest in T/37P to Gascorp. Exoil retains a 35% participating interest.

10.1.7 Farmin Agreement between Exoil and Gascorp with respect to T/38P

On 29 April 2008 Exoil entered into a farmin agreement with Gascorp in respect of T/38P and pursuant to which Gascorp agreed to meet the first $453,000 of Exoil's share of the costs of the 2D seismic programme recently completed in the Permit. As consideration, Exoil agreed to assign a 15% interest in T/38P to Gascorp. Exoil retains a 35% participating interest. The 15% interest held by Gascorp does not include any interest in the Spikey Beach Blocks described in 10.1.12 below.

10.1.8 Put and Call Option Agreements between Exoil and Gascorp with respect to T/37P

On 29 April 2008, Exoil entered into a Call Option Agreement and a Put Option Agreement with Gascorp relating to the 15% interest in T/37P acquired by Gascorp under the farmin agreement described in Section 10.1.6.

Under the Call Option Agreement, Exoil can call upon Gascorp to reassign the 15% interest in T/37P to Exoil. The consideration payable if the Call Option is exercised is the agreement of Exoil to repay to Gascorp the sum of $1,663,000 paid under the relevant farmin agreement, plus interest at 0.75% per month, together with the grant of a 1% overriding royalty on the 15% interest to be reassigned.

Under the Put Option Agreement, Gascorp can require Exoil to take a reassignment of the 15% interest. If the put option is exercised by Gascorp, Exoil must repay $1,663,000 to Gascorp plus interest at 0.75% per month and grant Gascorp a 1% overriding royalty on the 15% interest so reassigned.

10.1.9 Put and Call Option Agreements between Exoil and Gascorp with respect to T/38P

On 29 April 2008, Exoil entered into both a Call Option Agreement and a Put Option Agreement with Gascorp relating to the 15% interest in T/38P acquired by Gascorp under the farmin agreement described in Section 10.1.7.

Under the Call Option Agreement, Exoil can call upon Gascorp to reassign the 15% interest in T/38P to Exoil. The consideration payable if the Call Option is exercised is the agreement of Exoil to repay to Gascorp the sum of $453,000 paid under the relevant farmin agreement, plus interest at 0.75% per month, and grant a 1% gross overriding royalty interest in the proceeds of sale of any production from the permit and attributable to the 15% interest so reassigned.

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Under the Put Option Agreement, Gascorp can require Exoil to take a reassignment of the 15% interest. If the put option is exercised by Gascorp, Exoil must repay $453,000 to Gascorp, plus interest at 0.75% per month and grant a 1% gross overriding royalty interest in the proceeds of sale of any production from the whole of the permit and attributable to the 15% interest so reassigned.

10.1.10 Farmin Agreement between Exoil and Gascorp with respect to EPP34

On 29 April 2008, Exoil entered into a farmin agreement with Gascorp in respect of EPP34 pursuant to which Gascorp agreed to meet the first $525,000 of Exoil's share of the costs of the Trocopa seismic survey of 1,100 kms of new 2D data which was acquired in EPP34 during the quarter ended 30 June 2008. As consideration, Exoil agreed to assign a 10% interest in EPP34 to Gascorp. Exoil retains a 15% interest in the Permit.

10.1.11 Put and Call Option Agreement between Exoil and Gascorp with respect to EPP34

On 29 April 2008, Exoil entered into a Call Option Agreement and a Put Option Agreement with Gascorp relating to the 10% interest in EPP34 acquired by Gascorp under the farmin agreement described in section 10.1.10.

Under the Call Option Agreement, Exoil can call upon Gascorp to reassign the 10% interest in EPP34 to Exoil. The consideration payable if the Call Option is exercised is the agreement of Exoil to repay to Gascorp the sum of $525,000 paid under the relevant farmin agreement, plus interest at 0.75% per month and grant a 1% gross overriding royalty interest in the proceeds of sale of any production from the whole of the permit and attributable to the 10% to be reassigned.

Under the Put Option Agreement, Gascorp can require Exoil to take a reassignment of the 10% interest. If the put option is exercised by Gascorp, Exoil must repay $525,000 to Gascorp, plus interest at 0.75% per month and grant a 1% gross overriding royalty interest in the proceeds of sale of any production from the whole of the permit and attributable to the 10%so reassigned.

10.1.12 Farmin Agreement between Exoil and Beach with respect to the Spikey Beach Blocks in T/38P

On 11 April 2008, Exoil entered into a farmin agreement with Beach Petroleum (Exploration) Pty Ltd ("Beach") pursuant to which Exoil and Cue Energy Resources Ltd agreed to the establishment of the Spikey Beach Blocks Joint Venture ("SBBJV") and under which Beach has agreed to earn an 80% interest in the SBBJV by meeting 100% of the costs of the Spikey Beach-1 well. The Spikey Beach Blocks ("the Blocks") comprise an aggregate 18 graticular blocks within T/38P. The SBBJV is conducted as a separate joint venture from the T/38P Joint Venture. Three agreements have been signed by Exoil relating to the SBBJV:

(i) the Spikey Beach Blocks farmin agreement, under which Beach has agreed to farmin to the Blocks;
(ii) the Spikey Beach Co-ordination Agreement, pursuant to which the arrangements for co-ordinating the activities of the T/38P Joint Venture and SBBJV are described; and
(iii) the Spikey Beach Blocks JOA.

As a result of this farmin arrangement, the interests in the SBBJV are:

Exoil	10%
Cue Energy	10%
Beach	80%

10.1.13 Songa Venus Rig Arrangements with respect to WA-333-P

On 14 July 2008, the wholly-owned subsidiary of Exoil Limited, Hawkestone Oil Pty Ltd ("Hawkestone") acting in its capacity as Operator of the Browse Joint Venture, entered into two agreements relating to the steps taken to secure a rig to drill the Braveheart well in WA-333-P.

The first agreement, the Project Management Services Agreement, is between Hawkestone and Australian Drilling Associates Pty Ltd ("ADA") and other parties pursuant to which Hawkestone has agreed to engage ADA to provide drilling management services to Hawkestone. Hawkestone has agreed to pay to ADA aggregate management fees of $900,000.

The second agreement is the Drilling Co-operation Agreement between Hawkestone, ADA and all the other members of the consortium formed to contract the Songa Venus rig ("DCA"). Those consortium members are Hawkestone Oil Pty Ltd (ABN 23 052 812 236), Auralandia NL (ABN 53 004 913 884), Stuart Petroleum (Offshore) Pty Ltd (ABN 99 127 971 363), MEO Australia Limited (ABN 43 066 447 952), CNOOC Australia E&P Pty Ltd (ABN 85 118 934 062) and Anzon Energy Limited (ABN 43 097 972 364). Each of those consortium members is an *Operator* under the DCA and the italicised terms in this Section 10.1.13 are defined terms in the DCA.

Under the DCA, the various consortium members have agreed how they will share certain rig costs, including mobilisation, demobilisation and towing costs and have agreed to pay various fees to ADA associated with ADA's work in bringing the consortium together and securing shared services (logging contracts, work boats and the like).

Each *Operator* agrees to undertake its *Drilling Program* in accordance with the DCA. Clause 3.9 of the DCA requires that each *Operator* acknowledges that it will be required under the *Drilling Contract* to pay the *Drilling Contractor* the applicable *Daily Rate* for each *Day the Drilling Unit* is utilised in undertaking that *Operator's Drilling Program.*

The DCA is based around each *Operator* having provided an estimate of the number of days that that *Operator* will require for its *Drilling Program*. In the event that any *Operator's Drilling Program* results in what are defined as *Shortfall Days,* because that *Operator's Drilling Program* was shorter in duration than estimated, that *Operator* is liable to pay the cost of those *Shortfall Days*. However, if ADA cannot recover the cost of those *Shortfall Days* from any *Operator* the DCA provides that all of the *Operators* have joint and several liability to pay the cost of the *Shortfall Days* to ADA.

Under the terms of the DCA, ADA may require the *Operators* to provide ADA with any of:

- a bank guarantee ;
- a parent company guarantee ;
- advanced payment of funds into an escrow account held by ADA.

Although the DCA provides for specific liability for each *Operator* for other costs, including mobilisation and demobilisation costs, the DCA also provides for joint and several liability for those costs.

The primary risk that each of the members of the consortium is exposed to under the DCA is a failure by any other *Operator* or *Operators* to meet their contracted drilling obligations and associated costs, thus leaving a shortfall in payment to ADA which, after the various enforcement procedures set out in the ADA are exhausted in relation to the defaulting party, each consortium member must assume liability for. While each *Operator* has rights against a defaulting *Operator* to enable it to pursue recovery of any liability which it meets because of default, the recovery of such amounts might be uncertain and the prospect must exist that recovery might not be possible. However, the Company has no reason to believe that any of the *Operators* will default in any manner which will crystallise those joint and several liabilities.

These agreements together form the contractual framework pursuant to which Hawkestone has secured the Songa Venus rig to drill the Braveheart well and the services of ADA to manage the drilling programme.

10.1.14 Farmout Agreement between Exoil and MEO with respect to WA-359-P

On 24 October 2007, Exoil and a subsidiary of Cue Energy Resources Limited ("Cue Energy") entered into a farmin agreement with North West Shelf Exploration Pty Ltd ("North West"), a wholly owned subsidiary of MEO Australia Limited, relating to WA-359-P.

In consideration of the immediate assignment by Exoil to North West of a 30% interest in WA-359-P ("Initial Interest ") , North West agreed:

(i) to pay $216,667 to Exoil and Cue Energy to be divided between them equally (or as agreed); and

(ii) to meet all the costs associated with the year-3 commitment to acquire 250 line kms of new 2D seismic (now completed) attaching to WA-359-P.

On or before 1 January 2009, North West must must give a Notice to each of Exoil and Cue Energy stating whether Northwest irrevocably commits to the drilling of the First Well in WA-359-P or reassign the 30% interest to Exoil.

If Northwest does so irrevocably commits the notice must include all matters relating to a well proposal required under the JOA including details of the proposed location, target, drilling depth and estimated cost of the proposed well. Such a notice provides Northwest with the right to retain its interest in the Initial Farmout Interest and the JOA beyond 31 December 2008

On receipt of a notice from North West agreeing to commit to a well, Exoil has up to 70 days to decide whether it will meet not less than 5% and up to 10% of the Well Costs.

If both Cue Energy and Exoil make such an election then the respective Participating and Contributing Interests of Cue Energy, Exoil and Northwest shall be as follows:

Participant	Contributing Interest	Participating Interest
Northwest	90%	60%
Cue Energy	5%	20%
Exoil	5%	20%

If both Cue Energy and Exoil fail to make any election upon receipt of a notice from Northwest they must each assign and transfer to Northwest a further 5% Participating Interest. Thereafter, until the First Well is completed, Northwest must meet and pay for all ongoing exploration costs relating to the permit (including all well costs). In this circumstance the participating and Contributing Interests of Cue, Exoil and Northwest shall be as follows:

Participant	Contributing Interest	Participating Interest
Northwest	100%	70%
Cue Energy	0%	15%
Exoil	0%	15%

10.1.15 Farmout Agreement between Exoil and Gascorp with respect to WA-332-P, WA-333-P and WA-342-P

The farmin agreement provides for Gascorp to earn a 15% Participating Interest in each of the above permits by meeting the first US$1,120,000 of the aggregate obligations of the costs of the conduct of the seismic program which is a program for the acquisition of approximately 790 line kilometers of 2D seismic data to be carried out in the area of WA-332-P and WA-333-P. Gascorp's obligation includes subsequent processing of the seismic and the conduct of a site survey within that amount.

10.1.16 Put Option Agreement between Exoil and Gascorp with respect to WA-332-P, WA-333-P and WA-342-P

The Put Option agreement provides that Gascorp may put the interest being acquired under the farmout referred to in clause 10.1.15 above back to the present tenement holders (Hawkestone Oil Pty Ltd, Batavia Oil & Gas Pty Ltd, Alpha Oil & Natural Gas Pty Ltd and Goldsborough Energy Pty Ltd: collectively called the "Farmors").

Gascorp can call upon the Farmors to take a reassignment of the 15% interest in each of permits WA-332-P, WA-333-P and WA-342-P. The consideration payable if the Put Option is exercised is the agreement of the Farmors to repay to Gascorp the US$1,120,000 paid under the farmin agreement, plus interest at 0.75% per month and grant a 1% gross overriding royalty interest in the proceeds of sale of any production from the whole of the permit and attributable to the 15% to be reassigned.

The Put Option agreement provides that it will only be exercised if Exoil is in a working capital position where it is capable of repaying the relevant sum without having a significant negative impact on such working capital or the going concern status of Exoil. In the event that Exoil was in such a disadvantaged position, then Exoil can elect that the term of the Put Option be extended for a further period of 15 months. If at the end of such further period of 15 months that Exoil was again not then in a position to repay the relevant sum without having negative impact on the working capital or going concern status of Exoil, then the Put Option would lapse.

However, nothing in the Put Option Agreement disqualifies Gascorp from simultaneously exercising f the Put Option agreement and subscribing new share capital to Exoil Limited for an amount not less than the value of the Put Option and any increments of interest due upon its exercise.

Furthermore, nothing in the Put Option Agreement disqualifies Gascorp from accepting any other form of consideration offered by Exoil (such as other tenements or other non-cash interests) upon exercise of the Put Option agreement, provided that, accepting such consideration would not jeopardise the capital position or going concern basis of Exoil.

10.1.17 Senior Executives and Officers Option Plan

Under the Plan the Directors may issue Options to Eligible Persons. These are executive officers whether in a full time or part time position, including any director, secretary, public officer, or employee who is concerned or takes part in the management of the Company.

The total number of unissued Shares in respect of which Options have been granted under this Plan when aggregated with the number of outstanding options granted or shares issued pursuant to all employee share and option schemes established by the Company shall not exceed seven and a half percent (7.5%) of the aggregate of the total number of issued ordinary Shares in the capital of the Company and all outstanding options granted and all shares issued pursuant to all employee share and option schemes established by the Company as at the date of the letter of offer.

The Directors may in their sole discretion select Eligible Persons to whom Options shall be offered and determine the number of Options to be offered to an Eligible Person. The Directors may have regard to the length of the period of service and record of employment of the Eligible Person with the Company and the potential contribution of the Eligible Person to the Company.

The number of Options to be offered to an Eligible Person under the Plan shall be notified in a letter of offer from the Company. Acceptance of such offer shall be in writing in a form acceptable to the Directors.

Each Option shall entitle the Participant to subscribe for one Share upon exercise of the Option.

The Options may be exercised as follows:
as to 1/5 of the Options granted, during the first year from the date of grant.
as to 1/5 of the Options granted, during the second year from the date of grant.
as to 1/5 of the Options granted, during the third year from the date of grant.
as to 1/5 of the Options granted, during the fourth year of the date of grant.
as to 1/5 of the Options granted, during the fifth year from the date of grant.

To the extent that a holder of Options declines to exercise Options to the fullest extent possible in one year may exercise Options in respect of the shortfall in a later year.

If the Optionholder has not exercised his options in respect of all the shares the subject thereof by the fifth anniversary of the grant of the options, the options will lapse and he will not thereafter be able to acquire the shares.

Each Option may be only exercised at the Exercise Price.

The Options shall be exercisable wholly or in part in parcels of 100 or multiples thereof by delivering to the Company at its registered office a duly completed and executed Exercise Notice.

The options are not assignable or transferable without the prior written consent of the Directors, except in the case of the death of a participant in the Plan ("Participant") when options may be transmitted to the personal representative of the deceased.

The restrictions on exercise cease to have effect in a number of circumstances. These circumstances are that:

In the event of any proposed reconstruction or distribution of the issued capital of the Company, all the terms and conditions of this Plan shall be deemed to be modified so as to remove all restrictions on exercise thereof so as to permit such options to be immediately exercisable by the holders thereof.

In the event that either:

(i) a bona fide takeover bid pursuant to the Act is made for more than 50% of the issued share capital of the Company, or

(ii) the Company makes an announcement that it proposes to merge with another company by means of a Scheme of Arrangement to be effected pursuant to the Act, or

(iii) the Company proposes to effect a merger with any other company by any other lawful means;

all the terms and conditions of the Plan shall be deemed to be modified so as to remove all restrictions on exercise thereof so as to permit such options to be immediately exercisable by the holders thereof.

If a Participant ceases to be an Eligible Person except as set out below, the options held by the Participant and not at that time exercised shall be cancelled and shall cease to be of effect.

If a Participant:

(i) ceases to be an Eligible Person due to retrenchment or normal retirement from the workforce, all of the Participant's options shall be exercisable for a period of six months (or such longer period as the Directors may determine) from the date of retrenchment or retirement.

(ii) dies then the right of the Participant to exercise options not at that time exercised shall vest in the Participant's executor and/or administrator as the case may be.

The Plan may be terminated at any time by resolution of the Directors but any resolution shall not affect the rights of any existing holders of options issued in accordance with the Plan.

10.2 RIGHTS AND LIABILITIES ATTACHING TO SHARES IN THE COMPANY

10.2.1 Rights Attaching to Shares in the Company

A summary of the more significant rights attaching to the Company's shares, as provided by the constitution of the Company ("Constitution"), is set out below. This summary is not exhaustive, nor does it constitute a definitive statement of the rights and liabilities of the Company's Shareholders. To obtain such a statement, Proposing Investors should seek independent legal advice.

References to "the Act" in Section 10.2 are references to the Corporations Act 2001.

(a) **Ranking**: The shares are ordinary shares and rank equally in all respects.

(b) **Partly Paid Shares and Liability for Calls**: Shareholders holding partly paid shares will be liable to pay calls and make contributions in the event of the winding up of the Company in like manner as holders of partly paid shares in any other company limited by shares. At present there are no partly paid shares on issue.

(c) **Reports and Notices**: Shareholders are entitled to receive all notices, reports, accounts and other documents required to be furnished to them under the Constitution and the Act.

(d) **General Meetings**: Shareholders are entitled to be present in person or by proxy, attorney or representative to speak and to vote at general meetings of the Company. Shareholders may requisition general meetings in accordance with the Act and the Constitution.

(e) **Voting**: At a general meeting of the Company every Shareholder present in person or by proxy, attorney or representative shall on a show of hands have one vote and upon a poll every Shareholder present in person or by proxy, attorney or representative has one vote for every share held. A qualification to the above is that where a person is present at a meeting as proxy or representative for more than one Shareholder then on a show of hands that person shall have only one vote and not one vote for each Shareholder represented by him.

A Shareholder who holds a share that is not fully paid shall be entitled to a fraction of a vote equal to the proportion that the amount paid-up bears to the total issue price of the share.

The Constitution requires that directors of companies that have a sole director and a sole company secretary must state this when completing documents such as a proxy, appointment of corporate representative or power of attorney. The Constitution recognises the amendments to the Act which permit proprietary companies to not have a secretary and provides for such documents signed by a sole director of a company without a secretary to be valid.

(f) **Dividends**: The Directors may declare and authorise the distribution of dividends from the profits of the Company to be distributed to Shareholders according to their rights and interests.

(g) **Reduction of Capital**: The Company may only reduce its capital in such manner as may be permitted by the provisions of the Act from time to time.

(h) **Borrowing and Lending Powers**: The Company may borrow and lend in such manner as may be permitted by the provisions of the Act from time to time.

(i) **Winding Up**: Shareholders will be entitled in a winding up to share in any surplus assets of the Company in proportion to the shares held by them respectively, less any amount which remains unpaid on their shares at the time of distribution.

(j) **Transfer of Shares**: Subject to the Constitution and to the Act, the shares will be freely transferable.

(k) **Future Increases in Capital**: The allotment and issue of shares is under the control of the Board of Directors of the Company. Subject to restrictions on the allotment of shares to Directors or their Associates contained in the Constitution and the Act, the Directors may allot or otherwise dispose of shares on such terms and conditions as they see fit.

(l) **Variation of Rights**: The rights, privileges and restrictions attaching to the shares can be altered with the approval of a resolution passed at a separate general meeting of the holders of ordinary shares by a three-quarters majority of those holders who, being entitled to do so, vote to do so at that meeting or with the written consent of the holders of at least three-quarters of the ordinary shares on issue, within two months of that general meeting.

(m) **Directors**: The Constitution contains provisions relating to the rotation of Directors (other than any managing directors and alternate directors).

10.2.2 Rights Attaching to Options in Company

The terms and conditions of all of the Company's outstanding options are consistent with the NSX (and ASX) Listing Rules.

(a) **Options Expiring 31 December 2009 and Exercisable at $0.15 (15 cents):** There are 2,350,000 options presently outstanding and exercisable at 15 cents per share on or before 31 December 2009. These options will not be listed on the NSX at this time. The present terms and conditions of these options are as follows:

1. Each option confers the right to take up one ordinary fully paid share in the Company at a price of 15 cents.
2. The options shall expire on 31 December 2009.
3. The options are exercisable wholly or in part, by notice in writing to the Directors of the Company given prior to or on the expiry date. Shares issued pursuant to the exercise of the options will be allotted or issued not more than 14 days after the receipt of a properly executed exercise notice and application moneys in respect of the exercise of the options.
4. For shares subscribed for pursuant to the options, application money will be payable as to 15 cents in full on exercise of each option.
5. If the options comprised in any certificate are exercised in part only before the expiry date, the Company will issue the holder with a fresh option certificate for the balance of the options held by the holder and not yet exercised.
6. The options may be transferred at any time in whole or in part (subject to the requirements contained in the Company's constitution relating to transfers of shares and to any relevant laws, regulations or stock exchange requirements) prior to their expiry.
7. With regard to certain rights of Optionholders:
   - The options do not, in themselves, carry any voting rights or dividend entitlements.
   - Except as contained in these terms and conditions, there are no participating rights or entitlements inherent in the options and the Optionholders will not participate in new issues of securities offered to Shareholders during the currency of the options.
   - The Optionholder will be permitted to participate in new issues of securities on the prior exercise of the options in which case the Optionholder shall be afforded the period of at least 10 business days before the books' closing date (to determine entitlements to the issue) to exercise their options.
8. In the event of any reconstruction (including consolidation, sub-division, reduction or return) of the issued capital of the Company, the number of options or the exercise price of the options or both shall be reconstructed in the same proportion as the issued capital of the Company is reconstructed and in a manner which will not result in any additional benefits being conferred on Optionholders which are not conferred on Shareholders (subject to the same provisions with respect to rounding of entitlements as sanctioned by the meeting of shareholders approving the reconstruction of capital) but in all other respects the terms for the exercise of Options shall remain unchanged.
9. In the event of a bonus issue to Shareholders:
   - The number of shares over which the option is exercisable will increase to the number of shares which the Optionholder would have received if the option had been exercised before the record date for the bonus issue.
   - The Company shall notify each Optionholder and each relevant stock exchange (if any) within one month after the record date for a pro-rata bonus issue of the adjustment to the number of shares subject to the option.
10. Shares allotted pursuant to the exercise of the options will be allotted following receipt of all relevant documents and payment of the subscription moneys referred to in condition 4 above and will rank equally with the then issued ordinary shares of the Company.
11. The Company shall maintain a register of Optionholders in the same way as it is obliged to keep a register of Shareholders. All of the provisions of the Company's constitution relating to registers of Shareholders and transfer and transmission of shares shall apply mutatis mutandis to the register of Optionholders and to the options.
12. The Company is entitled to treat the registered holder of an option as the absolute owner of that option and accordingly, except as ordered by a Court of competent jurisdiction or as required by statute, shall not be bound to recognise any equitable or other claim to, or interest in, that option on the part of any person other than the registered holder thereof.
13. Nothing herein contained shall, if the Company obtains admission ("listed") to the Official List of the NSX, release the Company from complying with the Listing Rules of the NSX, and the Listing Rules shall override any relevant provision hereof and in particular:
   - Notwithstanding anything contained in these terms and conditions, if the Listing

Rules prohibit an act being done, the act shall not be done.

- Nothing contained in these terms and conditions prevents an act being done that the Listing Rules require to be done.
- If the Listing Rules require an act to be done or not to be done, authority is given for that act to be done or not to be done (as the case may be).
- If the Listing Rules would otherwise require these terms and conditions to contain a provision and it does not contain such a provision, these terms and conditions are deemed to contain that provision.
- If the Listing Rules require these terms and conditions not to contain a provision and it contains such a provision these terms and conditions are deemed not to contain that provision.
- If any provision of these terms and conditions is or becomes inconsistent with the Listing Rules, these terms and conditions are deemed not to contain that provision to the extent of the inconsistency.

(b) **Options Expiring 31 December 2009 and Exercisable at $0.20 (20 cents):** There are 1,950,000 options presently outstanding and exercisable at 20 cents per share on or before 31 December 2009. These options will not be listed on the NSX at this time. The terms and conditions of these options are the same as for the options described in 10.2.1(a) above, other than that the exercise price of these options is 20 cents rather than 15 cents.

10.3 ADDITIONAL INFORMATION

10.3.1 Corporate Governance

The Directors are responsible for the strategic direction of the Company, the identification and implementation of corporate policies and goals and monitoring of the business and affairs of the Company on behalf of the Shareholders.

Given that the Company is small, with limited activities and limited resources and has a board of four directors, it has not established a series of committees to address specific areas of corporate governance. Corporate governance is dealt with by the Board acting as a committee in relation to the various areas or issues required to be considered

Important to a culture of actively addressing the area of corporate governance is the Board's ongoing review of the Company's relevant practices. This is done via benchmarking against the ASX Corporate Governance Principles and Recommendations document issued by the ASX Corporate Governance Council.

The Council's eight principles are addressed by the Company and reported on in each annual report; where the corporate governance practices applied and specific instances where the Company follows alternative practices to those established by the Council are described.

The Board has established itself as two committees to separately address the areas of Audit and Compliance and Remuneration. Each of the Directors is a member of those committees, with interested Director(s) abstaining or being absent as required either by the Act or as necessary to avoid conflict or possible breach of their fiduciary duties.

10.3.2 Audit and Compliance Committee

The function of an Audit and Compliance Committee is to give additional assurance regarding the quality and reliability of financial information used by the Board and regarding the financial information provided by the Company pursuant to its statutory reporting requirements.

The Board believes that, as a public company, it has a responsibility to ensure independent accountability exists. When addressing the requirements of their audit and compliance functions, the focus of the Directors is to increase confidence in the credibility and reliability of financial statements and other financial information the Company releases to the public.

Aspects of the audit and compliance function addressed by the Board is considering any matters relating to the financial affairs of the Company, compliance with statutory requirements, adherence to NSX Listing Rules and issues relating to internal and external audit, plus examining any other matters of an audit or compliance nature that come to the attention of or are referred to the Board.

10.3.3 Remuneration Committee

The function of a Remuneration Committee is reviewing the remuneration policies and practices of the Company. Where relevant, this review covers compensation arrangements for executives, the Company's superannuation arrangements, the requirements for an employee share and option plan, performance reviews, succession planning and the fees of non-executive Directors.

When addressing these areas, the non-interested Directors who carry out these functions have access to independent advice and comparative studies on the appropriateness of remuneration arrangements. Existing director remuneration levels are as set out in clause 10.3.9.

In the event of exploration success or expansion of the Company's operations beyond those currently capable of being undertaken, the remuneration levels of Directors may increase: but not beyond the approved limit set by the Shareholders for directors fees. It should be noted that directors remuneration as fixed in general meeting does not include salary (and associated benefits, including superannuation) payable to Executive Directors.

10.3.4 Dividend Policy

The Company will not pay dividends in the foreseeable future.

10.3.5 Consents

PKF Chartered Accountants has given and not withdrawn its written consent to be named herein as the external Auditors of the Company in the form and context in which it is so named. In addition, **PKF** has given and not withdrawn its written consent to the despatch of this Information Memorandum with references to its Audit Report for the year ended 30 June 2008 being included herein, either expressly or by inference, in the form and context in which all such references are so included.

Save as set out below in relation to its auditing functions, **PKF** has had no involvement in the preparation of this Information Memorandum, other than the inclusion of such references, and has not given any professional or other advice in respect of any other part of this Information Memorandum. **PKF** does not accept any liability to any person in respect of any false or misleading statement in, or omission from, any other part of this Information Memorandum.

Michael J Martin has given and not withdrawn his written consent to be named herein as Independent Consulting Geologist to the Company in the form and context in which he is so named. In addition, he has given and not withdrawn his written consent to the despatch of this Information Memorandum with his Independent Consulting Geologist's Report as contained herein being included herein and to references thereto being included herein, either expressly or by inference, in the form and context in which they are included. He has had no involvement in the preparation of this Information Memorandum, other than the inclusion of his report and such references thereto, and has not given any professional or other advice in respect of any other part of this Information Memorandum. He does not accept any liability to any person in respect of any false or misleading statement in, or omission from, any other part of this Information Memorandum.

RPS Energy Pty Ltd ("RPS Energy") has given and not withdrawn his written consent to be named herein as an Independent Consulting Geologist to the Company in the form and context in which he is so named. In addition, he has given and not withdrawn its written consent to the despatch of this Information Memorandum with its Independent Consulting Geologist's Report as contained herein being included herein and to references thereto being included herein, either expressly or by inference, in the form and context in which they are included. RPS Energy has had no involvement in the preparation of this Information Memorandum, other than the inclusion of its report and such references thereto, and has not given any professional or other advice in respect of any other part of this Information Memorandum. RPS Energy does not accept any liability to any person in respect of any false or misleading statement in, or omission from, any other part of this Information Memorandum.

Link Market Services Limited ("Link") has given and not withdrawn its written consent to be named herein as the Share Registry to the Company in the form and context in which it is so named. In addition, Link has given and not withdrawn its written consent to the despatch of this Information Memorandum.

Link has had no involvement in the preparation of this Information Memorandum and has not given any professional or other advice in respect of any part of this Information Memorandum. Link does not accept any liability to any person in respect of any false or misleading statement in, or omission from, any part of this Information Memorandum.

10.3.6 Interests of Directors, Advisers and Named Persons

Except as otherwise set out herein or as previously disclosed to members in the Company's annual reports prepared in accordance with the provisions of the Corporations Act, no Director, expert or professional adviser named in this Information Memorandum now has, or during the last two years has had, any interest in the promotion of the Company or any property proposed to be acquired by the Company in connection with its formation or promotion. Further, no sums have been paid or agreed to be paid to a Director, expert or professional adviser in cash or shares or otherwise by any person (in the case of a Director) either to induce him to become, or to qualify him as, a Director or otherwise for services rendered by him in connection with the promotion or formation of the Company or (in the case of an expert or professional adviser) for services rendered by the expert or professional adviser in connection with the promotion or formation of the Company save and except that:

(a) **PKF** is the external Auditor of the Company and has received payment of professional fees for audit and other services as follows:
- $41,164 plus GST in relation to the audits for the financial years ended 30 June 2007 and 2008; and
- $$8,000 plus GST in relation to non-audit services and tax compliance.

(b) **Michael J Martin** is an Independent Consultant Geologist to the Company and has or will receive payment of professional fees for the preparation of his independent consulting geologist's report as contained herein in an amount of $17,850 plus GST.

(c) **RPS Energy Pty Ltd** is an Independent Consultant Geologist to the Company and has or will receive payment of professional fees for the preparation of its independent consulting geologist's report as contained herein in an amount of $32,883.46 plus GST.

(d) In accordance with the terms of its engagement, **Menzies & Partners**, Solicitors, has been paid professional fees of $25,000 plus GST in relation to the preparation of this Information Memorandum .

(e) The Directors and their Associates hold Shares and Options to acquire Shares as set out below and are remunerated as set out herein.

At the date of this Information Memorandum, no such payments have been made save as set out herein and, and also save as set out herein, all such payments made in the period since incorporation of the Company have been paid or are payable in cash.

10.3.7 Directors' Other Interests

In addition to the above, the Directors and the Company Secretary:

(a) hold Shares and options, as set out in Section 10.3.8; and

(b) are entitled to be remunerated, as set out in Section 10.3.9.

10.3.8 Directors' and Officers' Share and Option Holdings

The names of each of the Directors and Officers of the Company and proposed directors of the Company and the number, description and amount of securities in the capital of the Company presently held by each of them or on their behalf or in which they have or will have a relevant or beneficial interest are set out below.

DIRECTOR/ OFFICER	SHARES		OPTIONS		
	Number	**Percentage Holding**	**Number**	**Exercise Date**	**Exercise Price**
J M D Willis	2,312,500	2.268	400,000	31/12/2009	$0.15
E G Albers	73,484,984	72.36	200,000	31/12/2009	$0.15
P J Albers			200,000	31/12/2009	$0.15
G A Menzies	0	0	400,000	31/12/2009	$0.15
J G Tuohy	0	0	600,000	31/12/2009	$0.20
TOTAL	**75,797,484**	**74.63%**	**1,800,000**	**N/A**	**N/A**

* Ordinary shares in which P J and/or E G Albers has an interest.

10.3.9 Directors' and Officers' Fees, Remuneration and Other Entitlements

During the current year to 30 June 2009, the Directors and Officers of the Company plan to be remunerated at the initial rates and amounts set out in the table below (exclusive of GST).

DIRECTOR/ OFFICER	DIRECTORS FEES $	SALARY/ CONSULTANTS FEES $	SUPERANNUATION $	OTHER $	TOTAL $
J M D Willis	Nil	Nil	20,000	Nil	20,000
E G Albers	Nil	Nil	20,000	Nil	20,000
P J Albers	8,000	Nil	2,000	Nil	10,000
G A Menzies	8,000	Nil	2,000	Nil	10,000
J G Tuohy	N/A	Nil	Nil	Nil	Nil
TOTAL	$16,000	$NIL	$44,000	$NIL	$60,000

Details of remuneration for the years ended 30 June 2007 and 2008 are set out in Note 16 to the financial statements in Section 9. Additionally, details of related party transactions for those periods are set out in Note 17 to those financial statements. Aggregate directors' fees paid for the financial years ended 30 June 2007 and 2008 were $15,000 and $22,500 respectively.

10.4 DIRECTORS RESPONSIBILITY STATEMENT

The Directors of the Company state that they have made all enquiries that were reasonable in the circumstances and have reasonable grounds to believe that any statements by them in this Information Memorandum are true and not misleading or deceptive and that with respect to any other statements made in this Information Memorandum by persons other than the Directors, the Directors have made reasonable enquiries and have reasonable grounds to believe that persons making the statement or statements were competent to make such statements.

Each Director of the Company consents to the lodgement of this Information Memorandum with NSX and has not withdrawn that consent prior to this Information Memorandum being lodged.

This Information Memorandum is prepared on the basis that:

- certain matters may be reasonably expected to be known to professional advisers of the kind with whom Proposing Investors may reasonably be expected to consult; and
- information is known to Proposing Investors or their professional advisers by virtue of any Acts or laws of any State or Territory of Australia or the Commonwealth of Australia.

This Information Memorandum is dated the 12th day of November 2008.

Signed on behalf of Exoil Limited

James Willis

Chairman

SECTION 11: DEFINITIONS & GLOSSARY

DEFINITIONS

Terms defined in the Independent Expert's report have the meanings therein ascribed to them and throughout this Information Memorandum unless otherwise stated or unless inconsistent or repugnant with the context in which the expression is used. Other expressions are used throughout this Information Memorandum that are not defined in the Independent Expert's report and unless otherwise stated or unless inconsistent or repugnant with the context in which the expression is used, each of the following expressions have the meaning set out below:

$** or **A$:	means references to dollar amounts in Australian currency.
US$:	means references to dollar amounts in United States of America currency.
Act:	means the *Corporations Act 2001* as in force within Australia.
ASIC:	means Australian Securities and Investments Commission.
Associates:	has the meaning given to that term in the Act.
Business Day:	means, generally, those days other than a Saturday, Sunday, New Years Day, Australia Day, Good Friday, Easter Monday, Anzac Day, Christmas Day, Boxing Day and any other day on which NSX shall declare and publish is not a Business Day.
Company or **Exoil**:	means Exoil Limited (ABN 40 005 572 798).
Designated Authority:	means the Federal and/or State government responsible for the physical area that each respective Permit lies within.
Directors or **Board**:	means the Directors of the Company.
Group:	when used means the Company and its subsidiaries from time to time and when referring to any other corporate entity means that entity and its controlled or subsidiary entities.
Independent Expert:	means each of consulting geologist, Michael J. Martin or RPS Energy Pty Ltd who are each independent of the Company.
Information Memorandum:	means this Information Memorandum and as modified or varied by any supplementary Information Memorandum given by the Company from time to time.
Issuers:	means the legal entities which issue the securities quoted on the Official List of NSX.
Listing Rules:	means the Listing Rules of NSX
Members:	means those persons registered as the holders of Shares.
Native Title:	means the operation of the *Native Title Act 1993 (Cwlth)* under the auspices of the National Native Title Tribunal.
NSX:	means National Stock Exchange of Australia Limited.
Official List:	means the list of Issuers maintained by NSX in accordance with its Listing Rules.
Official Quotation:	means quotation by NSX on the Official List.
Proposing Investors:	means those individuals or entities who/that may consider making an investment in the Company by way of a purchase of Shares.
Petroleum Act:	*Offshore Petroleum Act 2006 (formerly the Petroleum (Submerged Lands) Act)* and all subordinate legislation made thereunder.
Q1, Q2, Q3, Q4:	means the first, second, third and fourth calendar quarters of the year respectively.
Shareholder	means a holder of Shares.
Shares:	means the ordinary shares of the Company.

GLOSSARY OF TECHNICAL & INDUSTRY TERMS

basin:	a depression of large size in which sediments have accumulated.
condensate:	hydrocarbons that spontaneously separate out from natural gas at the wellhead and condense to a liquid.
exploration well:	a well drilled to determine whether hydrocarbons are present in a particular structure.
graticular block:	means a graticular block as defined in the Petroleum Act
hydrocarbons:	naturally occurring organic compounds containing only the elements hydrogen and carbon existing as solids, liquids or gases.
Joint Venture:	the joint owners of a Permit who carry out the exploration activity in that Permit.
Joint Operating Agreement:	the formal agreement which governs the activities of the relevant Joint Venture – see Section 10.1.2.
lead:	inferred geologic feature or structural pattern requiring further investigation.
Operator:	the party in the Joint Venture changed with carrying out the exploration activities within that Permit
petroleum:	a generic name for hydrocarbons, including crude oil, condensate, natural gas and their products.
prospect:	a feature thought to be sufficiently defined to warrant the drilling of a well without the necessity of further investigation.
Permit:	is a permit issued by a Designated Authority in which the Company has an interest and within which the relevant Joint Venture carries out exploration activity.

reservoir: pervious and porous rocks (usually sandstone, limestone or dolomite) capable of containing significant quantities of hydrocarbons.

sediment: solid material, whether mineral or organic, that has been moved from its position of origin and redeposited.

seal: an impermeable rock (usually claystone or shale) that prevents the passage or further migration of hydrocarbons.

seismic survey: a technique for determining the detailed structure of the rocks underlying a particular area by passing acoustic shock waves into the strata and detecting and measuring the reflected signals.

source rocks: rocks (usually shales, claystone or coal) that have generated or are in the process of generating significant quantities of hydrocarbons.

spudding: commencing the drilling of a well.

structure: deformed sedimentary rocks where the configuration is such as to form a trap for migrating hydrocarbons.

tenement: is any form of permit or licence that can be issued by a Designated Authority with a view to the holder(s) of that tenement carrying out exploration activity.

trap: a body of reservoir rock , vertically or laterally sealed, the attitude of which allows it to retain hydrocarbons that have migrated into it.

ABBREVIATIONS

2D seismic	seismic data collected on a two-dimensional basis
3D seismic	seismic data collected on a three-dimensional basis
AVO	amplitude versus offset that describes a return from seismic data and can be an indicator of hydrocarbons
km	kilometre
km^2	square kilometre
m	metre
M	million
pa	per annum
TCF	trillion cubic feet (of gas)

SECTION 12: EXPLORATION PERMIT WORK OBLIGATIONS

Petroleum Exploration Permit No.	Title Holders	Locality Offshore Basin	Term	Commencement Date	Current Expiry Date	Minimum Work Requirements	Notes
VIC/P53	Stuart Petroleum Limited Exoil Limited Moby Oil & Gas Limited Cue Petroleum Pty Ltd	Gippsland	6 Years	16 October 2002	15 October 2004	Year 1: Geological and Geophysical Studies	Completed
				16 October 2004	15 October 2005	Year 2: Carry Out 200 km^2 3D Seismic Survey	Completed
				16 October 2005	15 October 2008	Year 3: Drill Two Wells	Obligation Farmed Out
				16 October 2008	15 October 2009	Year 4: Data Evaluation	
				16 October 2009	15 October 2010	Year 5: Drill One Well	
				16 October 2010	15 October 2011	Year 6: Drill One Well	
VIC/P45	Exoil Limited Moby Oil & Gas Limited	Gippsland	6 Years	16 May 2000	15 May 2001	Year 1: Geological and Geophysical Studies	Completed
				16 May 2001	15 May 2004	Year 2: Drill One Well	Completed
				16 May 2004	15 May 2008	Year 3: Drill One Well	Completed
				16 May 2008	15 May 2009	Year 4: Drill One Well	Under Application for Variation
				16 May 2009	15 May 2010	Year 5: Re-open Two Existing Wells	
				16 May 2010	15 May 2011	Year 6: Drill One Well	
T/37P	Cue Energy Resources Ltd Exoil Limited Gascorp Australia Pty Ltd	Bass Strait	6 Years	9 December 2004	8 December 2005	Year 1: Geological and Geophysical Studies	Completed
				9 December 2005	8 December 2006	Year 2: Geological and Geophysical Studies	Completed
				9 December 2006	8 December 2008	Year 3: Acquire 3,000 kms of New 2D Seismic	Obligation Farmed Out and Completed

Petroleum Exploration Permit No.	Title Holders	Locality Offshore Basin	Term	Commencement Date	Current Expiry Date	Minimum Work Requirements	Notes
				9 December 2008	8 December 2009	Year 4: Geological and Geophysical Studies	
				9 December 2009	8 December 2010	Year 5: Drill One Well	
				9 December 2010	8 December 2011	Year 6: Geological and Geophysical Studies	
T/38P	Cue Energy Resources Ltd Exoil Limited Gascorp Australia Pty Ltd	Bass Strait	6 Years	9 December 2004	8 December 2005	Year 1: Geological and Geophysical Studies	Completed
				9 December 2005	8 December 2006	Year 2: Geological and Geophysical Studies	Completed
				9 December 2006	8 December 2008	Year 3: Drill One Well	Obligation Farmed Out
				9 December 2008	8 December 2009	Year 4: Geological and Geophysical Studies	
				9 December 2009	8 December 2010	Year 5: Carry Out 200 km² 3D Seismic Survey	
				9 December 2010	8 December 2011	Year 6: Geological and Geophysical Studies	
WA-332-P	Hawkestone Oil Pty Ltd (Exoil Limited) Batavia Oil & Gas Pty Ltd Alpha Oil & Natural Gas Pty Ltd Goldsborough Energy Pty Ltd	Browse	6 Years	1 October 2002	30 September 2003	Year 1: Collect Data and Geoscience Studies	Completed
				1 October 2003	30 September 2004	Year 2: Seismic Acquisition, Geoscience Studies and Seismic Interpretation	Completed
				1 October 2004	31 March 2006	Year 3: Acquire 500 kms of New 2D Seismic	Completed
				1 April 2006	31 March 2007	Year 4: Seismic Interpretation, Geoscience Studies, Well Planning and Office Studies	Completed

Petroleum Exploration Permit No.	Title Holders	Locality Offshore Basin	Term	Commencement Date	Current Expiry Date	Minimum Work Requirements	Notes
				1 April 2007	31 March 2009	Year 5: Drill One Well	Committed To
				1 April 2009	31 March 2010	Year 6: Acquire 400 kms of New 2D Seismic	To Be Acquired in Year 5
WA-333-P	Hawkestone Oil Pty Ltd (Exoil Limited) Batavia Oil & Gas Pty Ltd Alpha Oil & Natural Gas Pty Ltd Goldsborough Energy Pty Ltd	Browse	6 Years	1 October 2002	30 September 2003	Year 1: Collect Data and Geoscience Studies	Completed
				1 October 2003	30 September 2004	Year 2: Seismic Acquisition, Geoscience Studies and Seismic Interpretation	Completed
				1 October 2004	31 March 2006	Year 3: Acquire 500 kms of New 2D Seismic	Completed
				1 April 2006	31 March 2007	Year 4: Seismic Interpretation, Geoscience Studies, Well Planning and Office Studies	Completed
				1 April 2007	31 March 2009	Year 5: Drill One Well	Committed To
				1 April 2009	31 March 2010	Year 6: Acquire 400 kms of New 2D Seismic	To Be Acquired in Year 5
WA-342-P	Hawkestone Oil Pty Ltd (Exoil Limited) Batavia Oil & Gas Pty Ltd Alpha Oil & Natural Gas Pty Ltd Goldsborough Energy Pty Ltd	Browse	6 Years	29 May 2003	28 May 2004	Year 1: Geotechnical Studies	Completed
				29 May 2004	28 May 2005	Year 2: Geotechnical Studies and Purchase Seismic Data	Completed
				29 May 2005	28 November 2006	Year 3: Acquire 500 kms of New 2D Seismic and Seismic Interpretation	Completed
				29 November 2006	28 November 2007	Year 4: Seismic Interpretation and Geotechnical Studies	Completed

Petroleum Exploration Permit No.	Title Holders	Locality Offshore Basin	Term	Commencement Date	Current Expiry Date	Minimum Work Requirements	Notes
				29 November 2007	28 November 2008	Year 5: Geotechnical Studies	Committed To
				29 November 2008	28 November 2009	Year 6: Drill One Well	
EPP34	Exoil Limited Moby Oil & Gas Limited National Energy Pty Ltd United Oil & Gas Pty Ltd Gascorp Australia Pty Ltd National Gas Australia Pty Ltd	Otway	6 Years	25 March 2004	24 March 2005	Year 1: Data Collection and Mapping	Completed
				25 March 2005	24 March 2006	Year 2: Reprocess Existing 2D Seismic Data, Mapping and Geological Studies	Completed
				25 March 2006	24 June 2008	Year 3: Acquire 600 kms of New 2D Seismic	Completed
				25 June 2008	24 June 2009	Year 4: Seismic Interpretation, Mapping and Studies	Committed To
				25 June 2009	24 June 2010	Year 5: Drill One Well	
				25 June 2010	24 June 2011	Year 6: Studies Review	
EPP35	Exoil Limited Gascorp Australia Pty Ltd Moby Oil & Gas Limited National Energy Pty Ltd	Otway	6 Years	17 August 2006	16 August 2007	Year 1: Geotechnical Studies	Completed
				17 August 2007	16 August 2008	Year 2: Reprocess Existing 2D Seismic Data and Geotechnical Studies	Completed
				17 August 2008	16 August 2009	Year 3: Carry Out 325 km^2 3D Seismic Survey	Committed To
				17 August 2009	16 August 2010	Year 4: Seismic Interpretation, Mapping and Studies	

Petroleum Exploration Permit No.	Title Holders	Locality Offshore Basin	Term	Commencement Date	Current Expiry Date	Minimum Work Requirements	Notes
				17 August 2010	16 August 2011	Year 5: Geotechnical Studies	
				17 August 2011	16 August 2012	Year 6: Drill One Well and Geotechnical Studies	
EPP36	Exoil Limited Gascorp Australia Pty Ltd Moby Oil & Gas Limited National Energy Pty Ltd	Otway	6 Years	17 August 2006	16 August 2007	Year 1: Geotechnical Studies	Completed
				17 August 2007	16 August 2008	Year 2: Geotechnical Studies	Completed
				17 August 2008	16 August 2009	Year 3: Acquire 1,100 kms of New 2D Seismic	Committed To
				17 August 2009	16 August 2010	Year 4: Geotechnical Studies	
				17 August 2010	16 August 2011	Year 5: Geotechnical Studies	
				17 August 2011	16 August 2012	Year 6: Drill One Well and Geotechnical Studies	
VIC/P61	Exoil Limited Gascorp Australia Pty Ltd Moby Oil & Gas Limited Southern Energy Pty Ltd	Otway	6 Years	8 February 2005	7 February 2006	Year 1: Acquire 760 kms of New 2D Seismic	Completed
				8 February 2006	7 December 2007	Year 2: Carry Out 450 km^2 3D Seismic Survey	Under Suspension and Extension Application
				8 December 2007	7 December 2008	Year 3: 3D Seismic Interpretation	
				8 December 2008	7 December 2009	Year 4: Geological and Geophysical Studies	
				8 December 2009	7 December 2010	Year 5: Drill One Well	

Petroleum Exploration Permit No.	Title Holders	Locality Offshore Basin	Term	Commencement Date	Current Expiry Date	Minimum Work Requirements	Notes
				8 December 2010	7 December 2011	Year 6: Office Studies	
WA-359-P	MEO Australia Limited Exoil Limited Cue Exploration Pty Ltd	Dampier	6 Years	1 February 2005	31 January 2006	Year 1: Geotechnical Studies	Completed
				1 February 2006	31 January 2007	Year 2: Reprocessing Existing 2D Seismic Data	Completed
				1 February 2007	31 January 2008	Year 3: Acquire 250 kms of New 2D Seismic	Obligation Farmed Out and Completed
				1 February 2008	31 January 2009	Year 4: Seismic Interpretation	Obligation Farmed Out
				1 February 2009	31 January 2010	Year 5: Drill One Well	Obligation Farmed Out
				1 February 2010	31 January 2011	Year 6: Geotechnical Studies	

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