# AUSAM RESOURCES LIMITED

## RESERVES EVALUATION, ASSESSMENT OF UNDISCOVERED RESOURCES AND UNDEVELOPED LAND VALUATION OF AUSTRALIAN GAS PROPERTIES

**Effective March 31, 2004**

**1046451**

# AUSAM SUMMARY

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Gilbert Laustsen Jung
Associates Ltd. Petroleum Consultants
4100,400 - 3rd Avenue S.W.,Calgary,Alberta,Canada T2P 4H2 (403) 266-9500 Fax (403) 262-1855

March 31, 2004

Project 1046451

Mr. Mark G. Avery
**Ausam Resources Limited**
260, 3000 Wesleylan Drive
Houston, Texas, 77027
USA

Dear Sir:

**Re: Australian Properties**
**Reserves Evaluation, Assessment of Undiscovered Resources and Undeveloped Land Valuation**
**Effective March 31, 2004**

Gilbert Laustsen Jung Associates Ltd. (GLJ) has completed an independent reserves assessment and evaluation, an assessment of undiscovered resources and an undeveloped land valuation of the Australian oil and gas assets of Ausam Resources Limited (the "Company"). The effective date of this evaluation is March 31, 2004. **All costs and values presented herein are in Australian Dollars.** As of the effective date, the exchange rate between Canadian and Australian Dollars was 1.0004 $AU/$CAN.

This report has been prepared for the Company for the purpose of annual disclosure and other financial requirements. This evaluation has been prepared in accordance with reserves definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook.

The following reports have been prepared and are included herewith:

- Reserves Evaluation, Queensland, Australia
- Assessment of Undiscovered Resources, Queensland, Australia
- Undeveloped Land Valuation, Australian Permits

It is trusted that this evaluation meets your current requirements. Should you have any questions regarding this analysis, please contact the undersigned.

Yours very truly,

**GILBERT LAUSTSEN JUNG ASSOCIATES LTD.**

ORIGINALLY SIGNED BY

Keith M. Braaten, P. Eng.
Vice-President, International

KMB/jem
Attachments

## INDEPENDENT PETROLEUM CONSULTANTS' CONSENT

The undersigned firm of Independent Petroleum Consultants of Calgary, Alberta, Canada has prepared an independent reserves assessment and evaluation, an assessment of undiscovered resources and an undeveloped land valuation of the **Ausam Resources Limited** Australian oil and gas properties and hereby gives consent to the use of its name and to the said estimates. The effective date of the evaluation is **March 31, 2004.**

In the course of the evaluation, Ausam Resources Limited provided Gilbert Laustsen Jung Associates Ltd. personnel with basic information which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which this report is based, were obtained from public records, other operators and from Gilbert Laustsen Jung Associates Ltd. nonconfidential files. Ausam Resources Limited has provided a representation letter confirming that all information provided to Gilbert Laustsen Jung Associates Ltd. is correct and complete to the best of its knowledge. The extent and character of ownership supplied by Ausam Resources Limited has been accepted following a review of documents outlining the terms of agreements related to each permit. Gilbert Laustsen Jung Associates Ltd. reserves the right to review all calculations referred to or included in this report and to revise the estimates in light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this report.

The accuracy of any reserves and production estimate is a function of the quality and quantity of available data and of engineering interpretation and judgment. While reserves and production estimates presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

Revenue projections presented in this report are based in part on forecasts of market prices, currency exchange rates, inflation, market demand and government policy which are subject to many uncertainties and may, in future, differ materially from the forecasts utilized herein. Present values of revenues documented in this report do not necessarily represent the fair market value of the reserves evaluated herein.

**PERMIT TO PRACTICE**
GILBERT LAUSTSEN JUNG ASSOCIATES LTD.

ORIGINALLY SIGNED BY
Signature: MYRON J. HLADYSHEVSKY

Date: March 31, 2004

**PERMIT NUMBER: P 2066**
The Association of Professional Engineers,
Geologists and Geophysicists of Alberta

ORIGINALLY SIGNED BY
HARRY JUNG
Gilbert Laustsen Jung Associates Ltd.

# INTRODUCTION

Gilbert Laustsen Jung Associates Ltd. (GLJ) was commissioned by AusAm Resources Limited (the "Company") to prepare an independent reserves assessment and evaluation, an assessment of undiscovered resources and an undeveloped land valuation of its oil and gas assets in Australia. The permits held by the Company are located in the States of Queensland, Western Australia and Victoria are illustrated on Maps Index 11, Index 2 and Index 3, respectively.

The evaluation was initiated in February 2004 and completed by April 2004. Estimates of reserves and projections of production were generally prepared using well information from the Company and the Operator of some of the properties to approximately March 31, 2004. The Company provided land, engineering, geological and other technical information not available in the public domain to approximately March 31, 2004. The Company has confirmed that, to the best of its knowledge, all information provided to GLJ is correct and complete as of the effective date.

This evaluation has been prepared in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook. The reserves definitions used in preparing this report (included herein under "Reserves Definitions") are those contained in the COGE Handbook and the Canadian Securities Administrators National Instrument 51-101 (NI 51-101).

The reserves evaluation was conducted on the basis of the Gilbert Laustsen Jung Associates Ltd. April 1, 2004 Price Forecast which is summarized in the Product Price and Market Forecasts section of this report.

GLJ conducted an extensive review of the exploration prospects and leads identified in the permits located in Queensland as discussed in the report titled Assessment of Undiscovered Resources. Based on the seismic and well information currently available for the Queensland permits and the preliminary nature of work done with respect to the Tinowon play on the Company's acreage to date, GLJ was unable to establish a positive expected monetary value for the identified exploration prospects.

Land value assignments for the permits consider the acquisition cost of the permit, current work commitments related to the permit, recent farm-in agreements related to the permit, offers to purchase interests in the permit and recent exploration and development activities in nearby permits.

The Evaluation Procedure section outlines the general procedures used in preparing this evaluation. The individual reports, attached hereto, provide additional evaluation details. The following summarizes evaluation matters that have been included/excluded in the analysis:

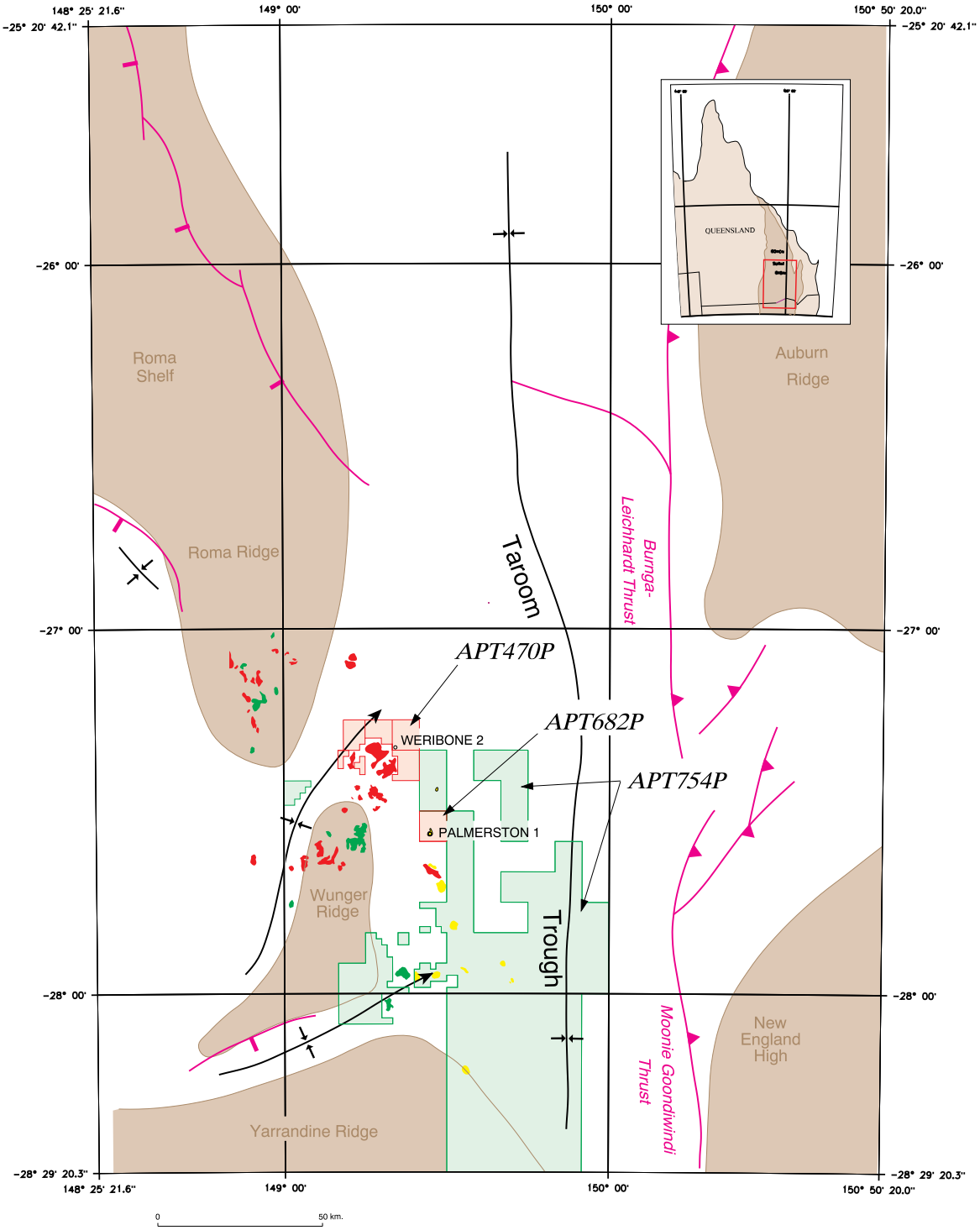
- provisions for the abandonment and reclamation of all of the Company's reserves wells have been included,
- general and administrative (G&A) costs and overhead recovery have not been included,
- undeveloped land values have been included in this evaluation.

Index 1

# Index Map
## ATP470P, ATP754P and ATP682P
## Queensland, Australia

Company: AusAm Resources Limited
Property: Surat Area

Effective Date: March 31, 2004
Scale: 1:2,000,000 s1046451/indm01

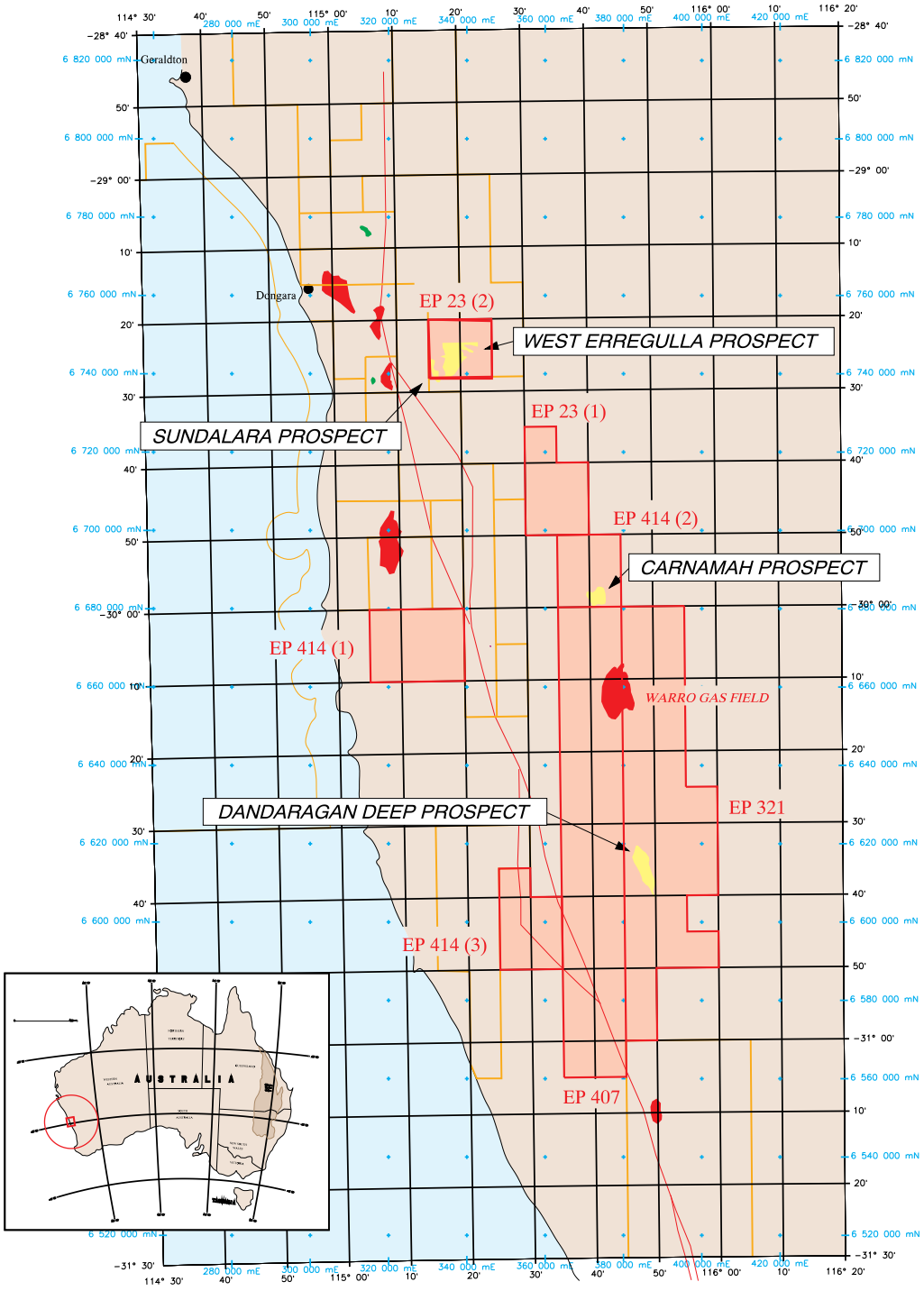


Index 2

# Index Map
## Western Australia

Company: AusAm Resources Limited
Property: Western Australia Permits

Effective Date: March 31, 2004
Scale: 1:1,750,000 s1046451/indm02

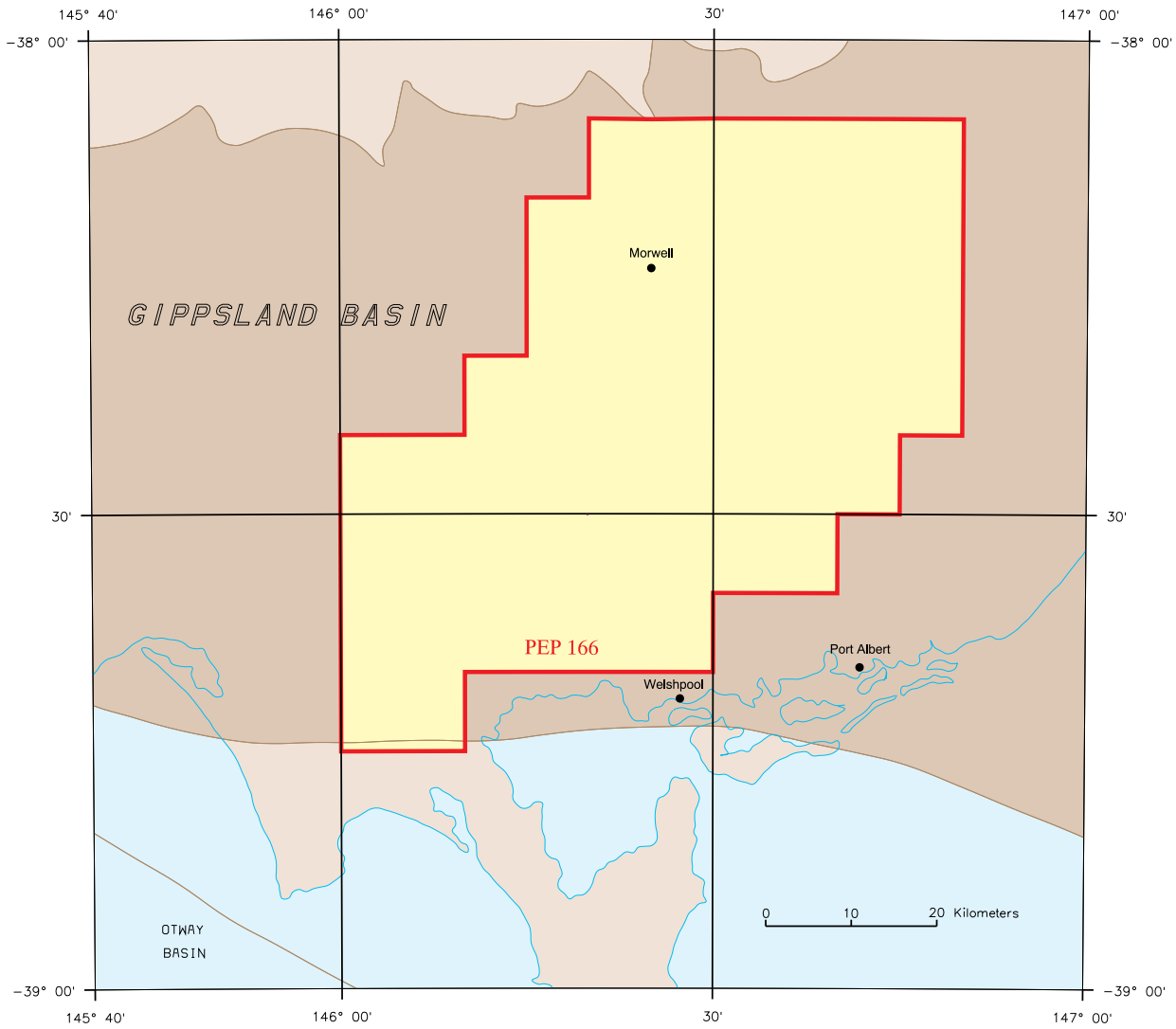


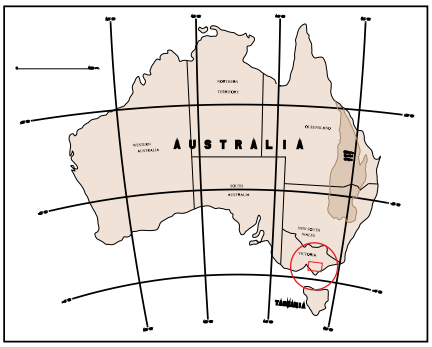
Index 3

# Index Map
# Victoria

Company: AusAm Resources Limited
Property: Victoria Permit

Effective Date: March 31, 2004
Scale: 1:750,000 s1046451/indm03



# SUMMARY

Reserves and values have been assigned to the Weribone-2 and Palmerston-1 wells, which are located in Authority to Prospect for Petroleum Number 470P and Authority to Prospect for Petroleum Number 682P, respectively. Details of the reserves evaluation including cash flow projections are included in the attached report titled Reserves Evaluation, Queensland, Australia. Reserves and values effective March 31, 2004, using the GLJ April 1, 2004 price forecast are summarized as follows:

| | **Total Probable** | **Total Probable Plus Possible** |
|---|---|---|
| **Marketable Sales Gas - MMCF** | | |
| Gross Company Reserves | 1,311 | 2,989 |
| Net After Royalty Reserves | 1,172 | 2,673 |
| | | |
| **Marketable Condensate - MBBL** | | |
| Gross Company Reserves | 11 | 32 |
| Net After Royalty Reserves | 10 | 28 |
| | | |
| **Before Tax Present Value - $M** | | |
| Discounted at 10% | 510 | 1,722 |

Undeveloped lands have been assigned a total value of 11,183 M$ as detailed in the attached report titled Undeveloped Land Valuation, Australian Permits.

# RESERVES DEFINITIONS

Reserves estimates have been prepared by Gilbert Laustsen Jung Associates Ltd. (GLJ) in accordance with standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook. The following reserves definitions are set out by the Canadian Securities Administrators in National Instrument 51-101 (NI 51-101; in Part 2 of Appendix 1 to Companion Policy 51-101CP) with reference to the COGE Handbook.

## Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology;
- specified economic conditions[1], which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

***Proved Reserves***
Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

***Probable Reserves***
Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

***Possible Reserves***
Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Other criteria that must also be met for the categorization of reserves are provided in [Section 5.5 of the COGE Handbook].

## Development and Production Status

Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

***Developed Reserves***
Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on

[1] *For the purposes of NI 51-101, the key economic assumptions will be the prices and costs used in the estimate, namely:*
*(a)* ***constant prices and costs*** *as at the last day of a reporting issuer's financial year; or*
*(b)* ***forecast prices and costs.***

production. The developed category may be subdivided into producing and non-producing.

***Developed Producing Reserves***
Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

***Developed Non-producing Reserves***
Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

***Undeveloped Reserves***
Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

**Levels of Certainty for Reported Reserves**

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves estimates are presented). Reported Reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves;
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with *reserves* estimates and the effect of aggregation is provided in Section 5.5.3 [of the *COGE Handbook*].

Incorporation of these guidelines means that total corporate proved reserves reflect a conservative estimate and proved plus probable reserves reflect a current "best estimate" of the oil and gas quantities that will be recovered.

## DOCUMENTED RESERVES CATEGORIES

Production and revenue projections are prepared for each of the following main reserves categories:

**Reserves Category**
Probable
Probable Plus Possible

**Production and Development Status**
Undeveloped

Note: Reserves for these properties are all classified as undeveloped.

The reserves evaluation report contains detailed documentation of reserves estimation methodology and evaluation procedures.

# EVALUATION PROCEDURE

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**LIST OF ABBREVIATIONS**

# EVALUATION PROCEDURE

The following outlines the methodology employed by Gilbert Laustsen Jung Associates Ltd. (GLJ) in conducting the evaluation of the Company's oil and gas properties. GLJ evaluation procedures are in compliance with standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook.

## INTEREST DESCRIPTIONS

The Company provided GLJ with current land interest information. This information was supported by the documents detailing the agreements or grants related to the permits. The Company provided a representation letter confirming accuracy of land information.

In GLJ's reports, "Company Interest" reserves and values refer to the sum of royalty interest and working interest reserves before deduction of royalty burdens payable. "Working Interest" reserves equate to those reserves that are referred to as "Company Gross" reserves by the Canadian Securities Administrators (CSA) in NI 51-101.

## WELL DATA

Pertinent interest and offset well data such as drill stem tests, workovers, pressure surveys, production tests, etc., were provided by the Company or were obtained from other operators, public records or GLJ nonconfidential files.

## ACCOUNTING SUMMARY

As the properties are all non-producing, there is no available accounting data.

## PRODUCTION FORECASTS

In establishing all production forecasts, consideration was given to access to gas markets, to the operator's plans for development drilling and to reserves and well capability. Generally, development drilling in an area was not considered unless there was some indication from the operator that drilling could be expected.

The on-stream date for currently shut-in reserves was estimated with consideration given to the following:

- proximity to existing facilities
- plans of the operator
- economics

## ECONOMIC PARAMETERS

Pertinent economic parameters are listed as follows:

a) The effective date is March 31, 2004.

b) Operating and capital costs were estimated in 2004 dollars and then escalated as summarized in the Product Price and Market Forecasts section of this report.

c) Economic forecasts were prepared on a before income tax basis. Detailed discounting of future cash flow was performed using a mid-year discount factor of 10.0 percent with all values discounted annually to March 31, 2004, on a mid-calendar-year basis.

d) State royalties at 10 percent of wellhead value have been included.

e) Well abandonment and lease reclamation costs for wells with reserves have been included at the property level. Additional abandonment and reclamation costs associated with non-reserves wells and facility abandonment and reclamation expenses have not been included in this analysis.

## INCOME TAX

Based on tax pool information provided by the Company, no income taxes are payable on the reserves evaluated herein.

## CONSTANT PRICE ANALYSIS

In the constant price analysis, the Queensland property was rerun using zero inflation and with a fixed price that reflects pricing at March 31, 2004. Results are presented in the Constant Price Analysis section.

## LIST OF ABBREVIATIONS

| | |
|---|---|
| BCF | billion cubic feet of gas at standard conditions |
| BOE | barrel of oil equivalent, in this evaluation determined using 6 MCF/BOE for gas, 1 BBL/BOE for all liquids, and 0 BOE for sulphur |
| BOPD | barrels of oil per day |
| BTU | British thermal units |
| BWPD | barrels of water per day |
| GOC | gas-oil contact |
| GOR | gas-oil ratio |
| GORR | gross overriding royalty |
| GWC | gas-water contact |
| MBBL | thousand barrels |
| MBOE | thousand BOE |
| MCF | thousand cubic feet of gas at standard conditions |
| MLT | thousand long tons |
| M$ | thousand dollars |
| MM$ | million dollars |
| MMBBL | million barrels |
| MMBOE | million BOE |
| MMBTU | million British thermal units |
| MMCF | million cubic feet of gas at standard conditions |
| MSTB | thousand stock tank barrels |
| MMSTB | million stock tank barrels |
| NGL | natural gas liquids (ethane, propane, butane and condensate) |
| NPI | net profits interest |
| OGIP | original gas-in-place |
| OOIP | original oil-in-place |
| ORRI | overriding royalty interest |
| OWC | oil-water contact |
| P&NG | petroleum and natural gas |
| psia | pounds per square inch absolute |
| psig | pounds per square inch gauge |
| PVT | pressure-volume-temperature |
| RLI | reserves life index, calculated by dividing reserves by the forecast of first year production |
| SCF | standard cubic feet |
| STB | stock tank barrel |
| WI | working interest |
| WTI | West Texas Intermediate |

**PRODUCT PRICE AND MARKET FORECASTS**
**April 1, 2004**

Gilbert Laustsen Jung Associates Ltd. has prepared its January 1, 2004, price and market forecasts as summarized in the attached Tables 1 and 2 after a comprehensive review of information. Information sources include numerous government agencies, industry publications and Origin Energy Resources Limited (Origin), the operator of significant assets in the Surat Basin. The forecasts presented herein are based on an informed interpretation of currently available data. While these forecasts are considered reasonable at this time, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market. These forecasts will be revised periodically as market, economic and political conditions change. These future revisions may be significant.

GLJ was advised by Origin that the current gas price in the Surat Basin is $2.80 AU/GJ and that the condensate price is equivalent to the price for Malaysian Tapis crude oil less $2.00 US/STB. For the gas price forecast, GLJ assumed that the price would increase in accordance with the rate of inflation. It is noted that the Malaysian Tapis crude oil price tracks the West Texas Intermediate (WTI) price fairly closely. For the condensate price forecast, the GLJ price forecast for WTI was used and adjusted for a differential of $2.00 US/STB and converted to Australian Dollars. Both prices were adjusted for transportation, compression and processing to determine a wellhead price.

The constant price analysis is based on the current gas price of $2.80 AU/GJ and the March 31, 2004 WTI crude price of $35.76 US/BBL resulting in a condensate price at the wellhead of $35.54 AU/BBL held constant.

**TABLE 1**
**AUSTRALIA**
**SURAT BASIN**
**SALES GAS PRICING**
**GLJ (2004-04) PRODUCT PRICE FORECAST**

| Year | Sales Gas Price at Sales Point $AUS/GJ | Sales Gas Price at Sales Point $AUS/MMBTU | Weribone Sales Gas Price at Sales Point $AUS/MCF | Palmerston Sales Gas Price at Sales Point $AUS/MCF | Infield Compression Fee $AUS/MCF | Pipeline Tarifs $AUS/MCF | Kincora Compression & Processing Fee $AUS/MCF | Weribone Sales Gas Price at Wellhead $AUS/MCF | Palmerston Sales Gas Price at Wellhead $AUS/MCF |
|---|---|---|---|---|---|---|---|---|---|
| 2004 | 2.80 | 2.95 | 3.37 | 3.49 | 0.36 | 0.70 | 0.30 | 2.01 | 2.13 |
| 2005 | 2.84 | 3.00 | 3.42 | 3.54 | 0.36 | 0.71 | 0.30 | 2.04 | 2.16 |
| 2006 | 2.88 | 3.04 | 3.47 | 3.59 | 0.37 | 0.72 | 0.31 | 2.08 | 2.20 |
| 2007 | 2.93 | 3.09 | 3.52 | 3.64 | 0.37 | 0.73 | 0.31 | 2.11 | 2.23 |
| 2008 | 2.97 | 3.14 | 3.57 | 3.70 | 0.38 | 0.74 | 0.31 | 2.14 | 2.26 |
| 2009 | 3.02 | 3.18 | 3.63 | 3.76 | 0.39 | 0.75 | 0.32 | 2.17 | 2.30 |
| 2010 | 3.06 | 3.23 | 3.68 | 3.81 | 0.39 | 0.76 | 0.32 | 2.20 | 2.33 |
| 2011 | 3.11 | 3.28 | 3.74 | 3.87 | 0.40 | 0.78 | 0.33 | 2.24 | 2.37 |
| 2012 | 3.15 | 3.33 | 3.79 | 3.93 | 0.40 | 0.79 | 0.33 | 2.27 | 2.40 |
| 2013 | 3.20 | 3.38 | 3.85 | 3.99 | 0.41 | 0.80 | 0.34 | 2.30 | 2.44 |
| 2014 | 3.25 | 3.43 | 3.91 | 4.05 | 0.42 | 0.81 | 0.34 | 2.34 | 2.48 |
| Thereafter | +1.5%/yr | +1.5%/yr | +1.5%/yr | +1.5%/yr | +1.5%/yr | +1.5%/yr | +1.5%/yr | +1.5%/yr | +1.5%/yr |
| **Constant** | | | | | | | | | |
| Mar. 31, 2004 | 2.80 | 2.95 | 3.37 | 3.49 | 0.36 | 0.70 | 0.30 | 2.01 | 2.13 |

Estimated Heating Values:

| | | |
|---|---|---|
| Weribone | 1140 | BTU/SCF |
| Palmerston | 1180 | BTU/SCF |

**TABLE 2**
**AUSTRALIA**
**SURAT BASIN**
**CONDENSATE PRICING**
**GLJ (2004-04) PRODUCT PRICE FORECAST**

| Year | Exchange Rate $U.S./AUS | WTI $U.S./BBL | Differential to WTI $U.S./BBL | Condensate Price at Sales Point $U.S./BBL | Condensate Price at Sales Point $AUS/BBL | Transportation from Wellhead $AUS/BBL | Condensate Price at Wellhead $AUS/BBL | Inflation |
|---|---|---|---|---|---|---|---|---|
| 2004 | 0.77 | 34.25 | -2.00 | 32.25 | 41.88 | 8.72 | 33.16 | 1.50% |
| 2005 | 0.77 | 29.00 | -2.00 | 27.00 | 35.06 | 8.85 | 26.21 | 1.50% |
| 2006 | 0.77 | 27.00 | -2.00 | 25.00 | 32.47 | 8.98 | 23.49 | 1.50% |
| 2007 | 0.77 | 25.00 | -2.00 | 23.00 | 29.87 | 9.12 | 20.75 | 1.50% |
| 2008 | 0.77 | 25.00 | -2.00 | 23.00 | 29.87 | 9.26 | 20.61 | 1.50% |
| 2009 | 0.77 | 25.00 | -2.00 | 23.00 | 29.87 | 9.39 | 20.48 | 1.50% |
| 2010 | 0.77 | 25.50 | -2.00 | 23.50 | 30.52 | 9.53 | 20.99 | 1.50% |
| 2011 | 0.77 | 25.75 | -2.00 | 23.75 | 30.84 | 9.68 | 21.16 | 1.50% |
| 2012 | 0.77 | 26.25 | -2.00 | 24.25 | 31.49 | 9.82 | 21.67 | 1.50% |
| 2013 | 0.77 | 26.50 | -2.00 | 24.50 | 31.82 | 9.97 | 21.85 | 1.50% |
| 2014 | 0.77 | 27.00 | -2.00 | 25.00 | 32.47 | 10.12 | 22.35 | 1.50% |
| Thereafter | 0.77 | +1.5%/yr | | +1.5%/yr | +1.5%/yr | +1.5%/yr | +1.5%/yr | +1.5%/yr |
| **Constant** | | | | | | | | |
| Mar. 31, 2004 | 0.763 | 35.76 | -2.00 | 33.76 | 44.26 | 8.72 | 35.54 | |

**AUSAM RESOURCES LIMITED**

**RESERVES EVALUATION**

**QUEENSLAND, AUSTRALIA**

**Effective March 31, 2004**

Prepared by
Keith M. Braaten, P.Eng.
T. Mark Jobin, P.Geol.
Roger J. Mahoney, P.Geoph.

# QUEENSLAND

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| Total Proved Plus Probable | | **54** |
| Total PPP | | **56** |

# Summary of Reserves and Values

Company: **AusAm Resources Limited**
Property: **Queensland**

Pricing: **GLJ (2004-04) Full Year**
Effective Date: **March 31, 2004**

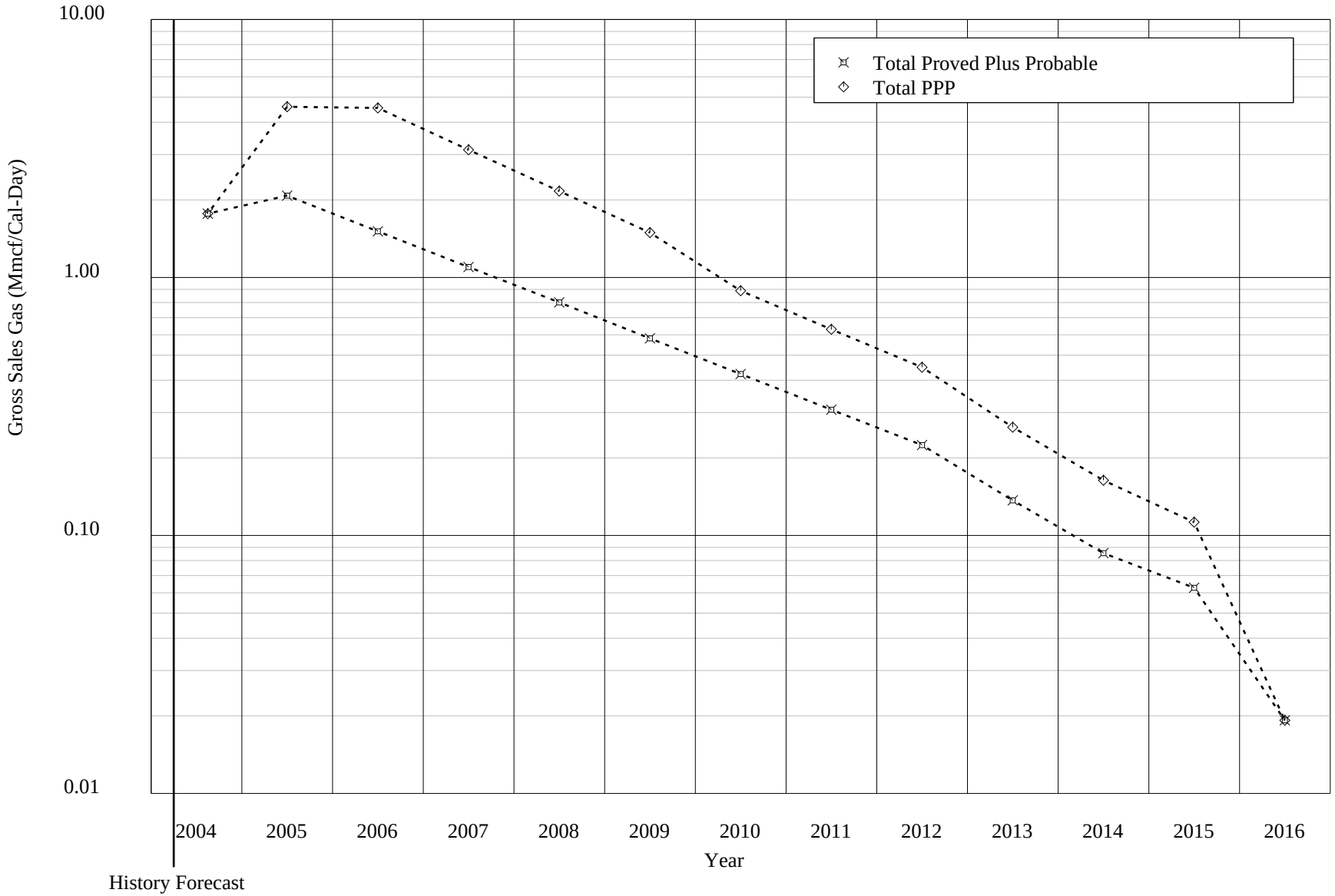
| | Total Proved Plus Probable | Total PPP |
|---|---|---|
| **MARKETABLE RESERVES** | | |
| **Gas - MMCF** | | |
| Gross Lease | 3159 | 7217 |
| Total Company Interest | 1311 | 2989 |
| Net After Royalty | 1172 | 2673 |
| **Natural Gas Liquids - MSTB** | | |
| Gross Lease | 27 | 87 |
| Total Company Interest | 11 | 32 |
| Net After Royalty | 10 | 28 |
| **Oil Equivalent - MBOE** | | |
| Gross Lease | 553 | 1290 |
| Total Company Interest | 230 | 530 |
| Net After Royalty | 205 | 474 |
| **BEFORE TAX PRESENT VALUE - $M** | | |
| 0.0% | 992 | 2873 |
| 5.0% | 719 | 2221 |
| 8.0% | 587 | 1907 |
| 10.0% | 510 | 1722 |
| 12.0% | 440 | 1555 |
| 15.0% | 347 | 1333 |
| 20.0% | 217 | 1025 |
| **FIRST 6 YEARS BEFORE TAX CASH FLOW - $M** | | |
| 2004 (9 Months) | -1021 | -1064 |
| 2005 | 584 | 12 |
| 2006 | 426 | 1315 |
| 2007 | 309 | 905 |
| 2008 | 227 | 633 |
| 2009 | 165 | 441 |

Oil Equivalent Factors:

Sales Gas - 6.0 mcf/boe  Condensate - 1.0 bbl/boe

Forecast Production
Gross Lease Sales Gas

Pricing: GLJ (2004-04) Full Year
Property: Queensland
Effective Date: March 31, 2004

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Run Date:

# Daily Production, Reserves and Present Value Summary

Company: **AusAm Resources Limited**
Property: **Queensland**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2004-04) Full Year**
Effective Date: **March 31, 2004**

| Entity Description | 2004 Gross Lease Production | | | | 2004 Company Interest Production | | | | Gross Lease Reserves | | | | | Company Interest Reserves | | | | | Before Tax 10% Dcf Present Value M$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gas mcf/d | Oil bbl/d | NGL bbl/d | BOE bbl/d | Gas mcf/d | Oil bbl/d | NGL bbl/d | BOE bbl/d | Gas Mmcf | Oil Mbbl | NGL Mbbl | Sulphur Mlt | BOE Mbbl | Gas Mmcf | Oil Mbbl | NGL Mbbl | Sulphur Mlt | BOE Mbbl | |
| Total Proved Plus Probable | | | | | | | | | | | | | | | | | | | |
| ***Palmerston*** | | | | | | | | | | | | | | | | | | | |
| ***Total Palmerston*** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ***Weribone*** | | | | | | | | | | | | | | | | | | | |
| ***Weribone 2*** | | | | | | | | | | | | | | | | | | | |
| Basal Rewan | 587 | 0 | 5 | 103 | 244 | 0 | 2 | 43 | 980 | 0 | 8 | 0 | 172 | 407 | 0 | 3 | 0 | 71 | 604 |
| Showgrounds | 1182 | 0 | 10 | 207 | 491 | 0 | 4 | 86 | 2180 | 0 | 18 | 0 | 382 | 905 | 0 | 8 | 0 | 158 | 1257 |
| ***Other Revenue and Expenses*** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -1351 |
| ***Total Weribone 2*** | 1770 | 0 | 15 | 310 | 734 | 0 | 6 | 129 | 3159 | 0 | 27 | 0 | 553 | 1311 | 0 | 11 | 0 | 230 | 510 |
| ***Weribone 3*** | | | | | | | | | | | | | | | | | | | |
| ***Total Weribone 3*** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ***Total Weribone*** | 1770 | 0 | 15 | 310 | 734 | 0 | 6 | 129 | 3159 | 0 | 27 | 0 | 553 | 1311 | 0 | 11 | 0 | 230 | 510 |
| ***Total Proved Plus Probable*** | 1770 | 0 | 15 | 310 | 734 | 0 | 6 | 129 | 3159 | 0 | 27 | 0 | 553 | 1311 | 0 | 11 | 0 | 230 | 510 |
| Total PPP | | | | | | | | | | | | | | | | | | | |
| ***Palmerston*** | | | | | | | | | | | | | | | | | | | |
| Palmerston-1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1294 | 0 | 37 | 0 | 252 | 323 | 0 | 9 | 0 | 63 | 450 |
| ***Total Palmerston*** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1294 | 0 | 37 | 0 | 252 | 323 | 0 | 9 | 0 | 63 | 450 |
| ***Weribone*** | | | | | | | | | | | | | | | | | | | |
| ***Weribone 2*** | | | | | | | | | | | | | | | | | | | |
| Basal Rewan | 587 | 0 | 5 | 103 | 264 | 0 | 2 | 46 | 980 | 0 | 8 | 0 | 172 | 441 | 0 | 4 | 0 | 77 | 655 |

# Daily Production, Reserves and Present Value Summary

| Entity Description | 2004 Gross Lease Production | | | | 2004 Company Interest Production | | | | Gross Lease Reserves | | | | | Company Interest Reserves | | | | | Before Tax 10% Dcf |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gas mcf/d | Oil bbl/d | NGL bbl/d | BOE bbl/d | Gas mcf/d | Oil bbl/d | NGL bbl/d | BOE bbl/d | Gas Mmcf | Oil Mbbl | NGL Mbbl | Sulphur Mlt | BOE Mbbl | Gas Mmcf | Oil Mbbl | NGL Mbbl | Sulphur Mlt | BOE Mbbl | Present Value M$ |
| Showgrounds | 1182 | 0 | 10 | 207 | 532 | 0 | 4 | 93 | 2180 | 0 | 18 | 0 | 382 | 981 | 0 | 8 | 0 | 172 | 1363 |
| ***Other Revenue and Expenses*** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -1351 |
| ***Total Weribone 2*** | 1770 | 0 | 15 | 310 | 796 | 0 | 7 | 139 | 3159 | 0 | 27 | 0 | 553 | 1422 | 0 | 12 | 0 | 249 | 667 |
| ***Weribone 3*** | | | | | | | | | | | | | | | | | | | |
| Weribone-3 Basal Rewan | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 857 | 0 | 7 | 0 | 150 | 386 | 0 | 3 | 0 | 68 | 537 |
| Weribone-3 Showgrounds | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1907 | 0 | 16 | 0 | 334 | 858 | 0 | 7 | 0 | 150 | 1115 |
| ***Other Revenue and Expenses*** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -1046 |
| ***Total Weribone 3*** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2764 | 0 | 23 | 0 | 484 | 1244 | 0 | 10 | 0 | 218 | 605 |
| ***Total Weribone*** | 1770 | 0 | 15 | 310 | 796 | 0 | 7 | 139 | 5924 | 0 | 50 | 0 | 1037 | 2666 | 0 | 22 | 0 | 467 | 1272 |
| ***Total PPP*** | 1770 | 0 | 15 | 310 | 796 | 0 | 7 | 139 | 7217 | 0 | 87 | 0 | 1290 | 2989 | 0 | 32 | 0 | 530 | 1722 |

**BOE Factors:**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| OIL | 1.00000 | RES GAS | 6.00000 | PROPANE | 1.00000 | ETHANE | 1.00000 |
| COND | 1.00000 | SLN GAS | 6.00000 | BUTANE | 1.00000 | SULPHUR | 0.00000 |

p:/s1046451/rems/econ/GLJ_2004-04_Full_Year/Queensland_RC00_ppv.htm

# GENERAL

AusAm Resources Limited (AusAm) holds interests in the following permits in the Surat/Bowen Basin located in the State of Queensland, Australia, as illustrated on Map 1, that have been assigned reserves in this evaluation:

| Permit | Equity Interest | Area |
|---|---|---|
| ATP 470P | 35%<br>(option to earn up to 45%)<br>excluding PL 71 area | 405 $km^2$<br>(85,000 acres) |
| ATP 682P | 25% | 75 $km^2$<br>(18,500 acres) |

***Weribone***

AusAm has exercised its option to earn a 35 percent equity interest in a portion of Authority to Prospect for Petroleum Number 470P (ATP 470P), hereinafter referred to as the Formosa Downs Farm-in Area by investing $1,500,000 to drill the Weribone-2 well. Under the terms of the agreement AusAm has an option to earn an additional equity interest in the Formosa Downs Farm-in Area at the rate of one percent per $100,000 of investment to a maximum additional 10 percent by investing an additional $1,000,000 It is likely that AusAm will fund the completion and tie-in costs of the Weribone-2 well, estimated at $650,000, thereby earning an additional 6.5 percent equity interest.

The Weribone structure is mapped as an extension of the Parknook Field as shown on Maps 2 and 3. The well Weribone-2 has been drilled to the top of the Showgrounds Formation and is currently waiting on a coiled tubing unit to drill underbalanced with nitrogen through the gas-bearing Showgrounds and Basal Rewan Formations. The Showgrounds and Basal Rewan Formations are known to be gas-bearing by virtue of production tests in offset wells Parknook-5 and Weribone-1.

For the purpose of this evaluation, it is assumed that AusAm will fund the completion and tie-in costs of Weribone-2, thereby earning a 41.5 percent interest in the Formosa Downs Farm-in Area.

***Palmerston***

The Palmerston structure is located in Authority to Prospect for Petroleum Number 682P (ATP 682P) as shown on Map-4. The well Palmerston-1 has been drilled through the Lower Tinowon Formation and is currently waiting on completion. AusAm earned a 25 percent interest in ATP 682P by funding its share of the costs to drill the Palmerston-1 well.

# GEOPHYSICS

AusAm has access to a large grid of seismic data, through the Queensland government, over the area of interest. The bulk of the data was acquired in the late 1970's and 1980's with what can be described as state of the art parameters at that time. The fold of the data was six in the 1970's acquisition, and increased to twelve for the 1980's data. The group intervals employed were larger than would be used today, resulting in a lower dominant frequency on the data, which will make delineation of thin beds more difficult.

The seismic data has not been stored under the best conditions, and this has resulted in deterioration in the quality of the seismic tapes. Some of the tapes suffer from sticktion, the magnetic material peels off when the tapes are being read. In order to read these tapes, they need to be baked prior to loading. If the deterioration is not too severe, baking will work; if the deterioration is too severe, baking will not help. In the case where the original data cannot be reclaimed from the original tapes, then scanning of the paper stacks is undertaken. The scanned data allows some post stack processing to be undertaken, possibly migration and refined filtering. This will improve the final appearance of the data, but is not a good substitute for the missed opportunity to fully reprocess the data. Reprocessing with current software would provide the opportunity to refine the dynamics and the statics; the statics are particularly problematical in the Surat Basin. In the future, when seismically assessing the merits of various structures, the structures defined by reprocessed data should have a higher rating.

AusAm's partner, Origin Energy Resources Limited (Origin) has completed detailed interpretation in the Weribone area, mapping the structure for the Showgrounds and Basal Rewan test at the Weribone-2 location. GLJ reviewed this work in Origin's office. Significantly, the mapping carried out by Origin shows the structural differences that can occur through reprocessing the data with revised statics. In the Weribone area, the current structure being drilled is removed in location from the original mapping. This emphasizes the point that if old, unreprocessed data is used in the mapping, an uncertainty in structural mapping will occur.

Origin had also done detailed mapping in the Palmerston area, using a set of reprocessed data. The Palmerston well was located using this reprocessed data set. GLJ carried out independent mapping in this area using data loaded on the MBA Petroleum Consultants (MBA) workstation. The key map produced is on the base of Wallabella coal, which should provide a good representation of structure at Lower Tinowon level.

The sandstone development in the Upper Tinowon in the Palmerston well was not as thick as would have been expected. Using the analogy to the Myall Creek #3 well, a thicker Upper Tinowon sandstone development would have been expected. Possibly, the coalescing of the upper and lower Wallabella coals is only one of the parameters that control sandstone development.

# GEOLOGY

## Surat/Bowen Basin

The AusAm interest blocks are located on the western flank of the Surat/Bowen Basin. The Bowen Basin and the overlying Surat Basin are located in east central Queensland and extend southwards into New South Wales, Australia (Map I-1). The Bowen Basin is comprised of two main depocenters, the Taroom Trough and the Denison Trough. The Taroom Trough forms the southern extent of the Bowen Basin and underlies the interest blocks. The Taroom Trough is a north-south trending half graben that deepens to the north and contains up to 9,000 meters of Permian to Triassic age sediment. The trough is bounded to the east by a thrust fault system. On the western margin of the trough the Permian to Triassic sediments onlap a series of basement highs (Roma Shelf, Wunger and Yarrandine Ridges) and are progressively truncated by the regional sub Jurassic unconformity. The Jurassic to Cretaceous age sediments of the Surat Basin unconformably overlay the southern portion Bowen Basin sequence. The Surat Basin is a north-south trending intracratonic basin, which covers an area of approximately 270,000 square kilometers. The Surat Basin contains up to 2,500 meters of Jurassic to Cretaceous age sediment, with the thickest section accumulating in the Mimosa syncline that parallels the north-south axis of the Taroom Trough.

### *Stratigraphy*

The general stratigraphy of the west Surat/Bowen Basin is illustrated on Table 1 (taken from Orgin Energy Resources Limited). The Bowen Basin evolved in three phases. The basin was initiated with rifting in the Late Carboniferous or Early Permian. During this phase structuring in the basin was extensional and volcanic and associated volcanoclastic sediments were deposited in the Taroom Trough.

The Early Permian rifting was followed by a period of low subsidence rates in the basin (sag phase) during Middle Permian. Rapid subsidence and basin filling due to thrusting and crustal thickening in the east mark the onset of foreland loading in the Late Permian. This foreland loading controlled subsidence in the basin until the Middle Triassic. Structuring in the basin during this phase was compressional. Mild compressive events started in the basin in the late Early Permian and increased in intensity until the Middle Triassic. A thick package of Late Permian to Middle Triassic sediments was deposited into the subsiding basin. The Permian Upper Back Creek Group unconformably overlies the Permo-Carboniferous volcanics that form the

economic basement on the western flank of the basin. These sediments consist of fluvial lacustrine coals, conglomerates, sandstones, and siltstones with shale and minor amounts of limestone deposited during minor marine transgressions. The regressive prograding deltaic and alluvial sediments of the Blackwater Group overlie these sediments. The Permian sediments are in turn unconformably overlain by the Early Triassic redbeds of the Rewan Formation. Sediments in the Middle Triassic were deposited in fluvial lacustrine to coal swamp environments and include the fluvial Showgrounds sandstone, the transgressive Snake Creek mudstone and the fluvial deltaic Moolayember Formation.

The continued movement of the thrust front into the western part of the basin and the associated uplift and erosion ended sedimentation in the Bowen Basin. This erosion produced a peneplain and the regional unconformity on which the Surat Basin was developed. The Surat Basin was initiated in the Early Jurassic with deposition of fluvial lacustrine sediments into a broad, regionally subsiding intracratonic basin. The Jurassic section is characterized by alternating lower sandstone dominated intervals and upper mudstone dominated intervals. Sandstone sequences include the Precipice sandstone and Boxvale sandstone members. The Cretaceous section conformably overlies the Jurassic section and consists of fluvial and nearshore sands overlain by extensive marine shale deposited in response to a basin wide transgression.

Structures in the Surat Basin were generally formed by compaction and drape over basement topography and by rejuvenation of structural trends within the underlying Bowen Basin and basement. In the Late Cretaceous, the basin was tilted to the south and this event was accompanied by a marine regression and extensive erosion in the northern part of the basin. Minor extensional movements associated with the formation of the Tasman Sea are the last events recognized events to have an effect on the Surat and Bowen Basins.

***Hydrocarbon Occurrence***

The interest blocks are located on the proven, widely explored and gas prone western flank of the basin. Numerous hydrocarbon accumulations have been drilled in this portion of the basin. Hydrocarbons have been found in reservoirs that range in age from the Permian to the Early Jurassic at depths ranging from 1,000 meters to 3,000 meters. The main productive horizons include the Jurassic Precipice and Boxvale sandstones, sandstones in the Triassic Showgrounds, Moolayember and Rewan Formations, the Permian Tinowon Formation and Basement Timbury Hills Formation.

Exploration in the western flank of the basin has generally concentrated on structural closures, however most of the traps likely have a stratigraphic component. The major reservoir units were deposited in a complex fluvial deltaic system and the stratigraphic component of trapping is controlled by the lateral distribution of reservoir facies and lateral and vertical changes in porosity and permeability.

It is generally concluded that most if not all of the hydrocarbons in the Surat/Bowen Basin are sourced from Permian coals and carbonaceous shales in the Taroom Trough. The number of hydrocarbon accumulations encountered indicates extensive lateral migration of the Permian sourced hydrocarbons out of the Taroom Trough to the western flank of the basin. Generally Permian reservoirs are located closet to the trough while the location of younger reservoirs is controlled by progressive updip pinchout of regional seals, the Rewan Formation and the Snake Creek Mudstone.

**ATP- 470, ATP-682 and ATP-754**

To date AusAm has participated in the drilling of two wells in the western Surat Basin, the Weribone-2 well in ATP-470 and the Palmerston 1 well in ATP-682.

***Weribone-2***

The Weribone-2 well was spudded on March 7, 2004 and drilled to an intermediate casing depth of 2125 meters. A coil-tubing unit will be used to drill the target zones in the second quarter of 2004. The primary target zones in the well are the Showgrounds sandstone and the Basal Rewan sandstone.

The Early Triassic age Rewan Formation consists of a sequence of fluvial channel and floodplain deposits. The Rewan section consists of basal quartz rich coarse-grained sandstone and conglomerates and an upper finer grained lithic sandstone sequence. The Basal Rewan has been interpreted as a high-energy alluvial plain to braided stream deposit with the quartz rich sands being derived from basement highs to the west. The upper Rewan section is interpreted as a lower energy fluvial to lacustrine deposit. The Basal Rewan is the primary reservoir in the Rewan section. Only small quantities of gas have been tested from the upper Rewan section and this section may act as a seal between the Basal Rewan reservoirs and overlying reservoirs in the Showgrounds sandstone.

The Middle Triassic age Showgrounds sandstone overlies the Rewan and is overlain by the Middle Triassic Snake Creek mudstone. The Snake Creek is a regional seal in the area. The Showgrounds sequence consists of a basal coarse-grained sandstone/conglomerate deposited in a high-energy fluvial channel system. More lacustrine deposits progressively replace these channel sands. This sequence is interpreted to represent the gradual flooding of an alluvial plain by a rising lake. The highest reservoir quality in the Showgrounds is associated with the lower, coarse-grained fluvial sands.

The Weribone-2 well is located in ATP-470 just east of PL-71. PL-71 contains the Warroon, Namarah and Parknook fields (Map 1). All three of these fields produce gas from both the Showgrounds sandstone and the Basal Rewan. Two wells, Weribone-1 and Weribone East-1, have been drilled on the Weribone structure to the east of the Weribone-2 location. The Weribone structure is currently interpreted to be an extension of the Parknook Field.

GLJ has reviewed available well logs, well completion reports, core, and test data for wells within the Parnook/Weribone structure. GLJ has determined reservoir parameters (net pay, porosity and water saturations) for the Showgrounds and Basal Rewan sands in these wells in order to gain some understanding of areas being drained by producing wells.

The Weribone-2 well is located 1.8 kilometers east of the Parknook-5 well and approximately 1.4 kilometers west of the Weribone-1 well. In the Parknook-5 well, core data over the Showgrounds suggests that the lower sands in the zone have much better reservoir quality than the upper portions of the zone. DST 1 run over the Showgrounds in the Parknook-5 well flowed gas at a rate to small to measure with a recovery of 5 barrels of gas cut mud and 80 barrels of gas cut water. GLJ has interpreted that there is 7.7 meters of net porous sand in the Showgrounds in this well. The average porosity of the zone has been estimated at 12.9 percent. It is noted that the Showgrounds water test in this well is approximately 20 meters structurally above the pool gas water contact as interpreted from log and test data in the Rednook 1 well. Further, the water test in this well is structurally above the Showgrounds gas test at Weribone-1. This suggests that there are discontinuities within the reservoir. Compartmentalization of the reservoir can be explained by lateral facies variation and variable reservoir quality across the pool. DST 2 in the Parknook-5 well tested the lower and Basal Rewan, and flowed gas at a rate of 1.38 MMCFD. The well was completed in the Basal Rewan but has only produced a small amount of gas to date. This low recovery to date may indicate compartmentalization of the Basal Rewan reservoir. Based on a review of log and core data, GLJ has estimated a net gas pay of 2.7 meters in the Basal Rewan sand at average porosity and water saturations of 13.5 percent and 60 percent respectively.

A DST over the Showgrounds sandstone in the Weribone-1 well flowed gas at a rate of 150 MCFD and recovered 18.3 meters of gas cut mud. Based on a review of log and core data GLJ has interpreted a net pay of 3.1 meters in the Showgrounds in this well at average porosity and water saturation of 12.6 percent and 35 percent respectively. The Basal Rewan section was not tested in this well, but based on a review of log and core data GLJ has interpreted a net pay of 2.0 meters in the Basal Rewan in this well. Average porosity and water saturation values have been estimated at 14 percent and 60 percent, respectively. Reservoir parameters determined in the Parknook-5 and Weribone-1 wells were used to estimate reservoir parameters for the Weribone-2 location.

Origin's depth structure mapping on the top of the Showgrounds sandstone and on the top of Bandanna Formation (Maps 2 and 3 respectively) indicate that the Weribone-2 well will penetrate the target horizons in crestal position in the Weribone structural culmination. The Weribone-2 well is prognosed to penetrate the Showgrounds approximately 22 meters updip from the Weribone-1 well and 10 meters updip from the Parknook-5 well. The Weribone-2 well will penetrate the Basal Rewan approximately 26 meters updip from the Weribone-1 location but 21 meters downdip from the Parknook-5 well. It is noted that in the original processing of the seismic data the Weribone-2 location was mapped in a flank or low position at the Showgrounds level and outside of closure at the Basal Rewan (Bandanna) level.

The greatest risk associated with the Weribone-2 location is reservoir quality and extent of the reservoir horizons. This is reflected in the different drainage areas assigned by GLJ in its probable and possible reserve estimates.

***Palmerston-1***

The Palmerston-1 well was spudded on January 31, 2004 and drilled to a total depth of 2815 meters. The Palmerston-1 exploratory well was drilled targeting liquids rich gas in the Upper Tinowon sandstone. This is the main gas-producing interval in the offsetting Waggamba, Myall Creek and Churchie Fields (Map 1). Seismic and well data supported the interpretation of an Upper Tinowon fairway at Palmerston and a well-defined structural closure at the Upper Tinowon level at the location. The Lower Tinowon was considered a secondary target in the well.

In the area, the Upper Tinowon is defined as the sandstone unit immediately above the Wallabella coal member. The intra Wallabella sands were deposited within the Wallabella coals and the Lower Tinowon sand occurs below the coals. The Upper Tinowon sandstones are described as medium to coarse-grained sandstones that were deposited in complex fluvial-deltaic system. The

Lower Tinowon section consists of interbedded fine to coarse-grained sandstones shales and coals. The sequence is interpreted to represent stacked fluvial channel fill deposits. Log, core and test data suggest that the reservoir quality of the lower sand is generally poorer than the Upper Tinowon. This poorer quality is due to the high amounts of clays within the lower sandstone section.

On drilling, the Upper Tinowon section was very poorly developed and tight. However, well log data, MDT pressure data and sidewall core data indicate that the Lower Tinowon sands may contain gas. No open hole drill stem tests were run in the well because of the anticipated high pressure in the well at the target depth. The well has been cased and a cased hole test of the Permian age Lower Tinowon sandstone has been proposed. The Lower Tinowon section contains poor reservoir quality sands and it is uncertain if there is sufficient reservoir permeability for the zone to produce.

The parameters required for a volumetric estimate of potential OGIP for the Palmerston accumulation carry some degree of uncertainty; therefore a probabilistic approach was adopted to provide a range in gas-in-place values that result from the expected range in input parameters. Ranges of gross rock volume, net to gross ratios, porosity, and water saturation were determined from well data, GLJ's seismically mapped anticlinal closure at the base Wallabella coal level (Map 4), and reservoir parameters from log analysis of the Palmerston-1. The resulting frequency distributions were input into a probabilistic simulation model and a cumulative probability distribution for OGIP was generated for the reservoir. The potential OGIP for the Palmerston well has been taken at a 10 percent confidence level. This corresponds to a value of 2.38 BCF.

In the petrophysical analysis of the Lower Tinowon section in the Palmerston-1 well, shale corrected porosity values were estimated from a neutron density crossplot. Water saturations were calculated using the Simandoux equation, with a water resistivity of 0.15 at formation temperature. Net gas pay was estimated using an 8 percent porosity cutoff in the low case and a 6 percent porosity cutoff in the high case.

# RESERVES

## Weribone

Probable undeveloped reserves have been assigned to the Showgrounds and Basal Rewan Formations in the Weribone-2 well based on expected wellbore parameters over a drainage area of 400 acres as detailed in Table 2.1. The expected wellbore parameters are an average of the wellbore parameters encountered in wells Parknook-5 and Weribone-1. The drainage area is based in part on the mapped structural size and the drainage areas of successful wells in the adjacent Parknook and Namarah Fields that had average drainage areas of 330 and 400 acres in the Showgrounds and Basal Rewan Formations, respectively.

It is noted that the majority of wells in the Parknook and Namarah Fields were drilled with overbalanced drilling mud systems and sustained significant formation damage. The well Parknook-3 was drilled underbalanced through the Basal Rewan Formation and flowed 22.9 MMCFD while drilling. The Showgrounds and Basal Rewan Formations were completed and have produced approximately 1.5 and 3.3 BCF, respectively. The poor performance experienced in the Basal Rewan Formation in other wells in the two fields is attributed to formation damage. The Showgrounds Formation has performed somewhat better with two of the three completed wells producing over 1.5 BCF per well. Reservoir parameters and recoverable reserves for the Parknook and Namarah Fields are presented in Table 2.2.

The Showgrounds and Basal Rewan Formations are typically of relatively low permeability with high clay content that swells when drilled using conventional mud systems, thereby causing a degradation of the permeability. It is AusAm's opinion that the use of nitrogen based underbalanced drilling techniques will mitigate formation damage and improve recovery from these reservoirs. Experience by other operators in the basin supports this view.

Possible undeveloped reserves have been assigned to an additional well to be drilled into the Weribone structure to improve drainage from the entire mapped area.

Condensate reserves have been assigned to the Showgrounds and Basal Rewan Formations using an expected yield of 8 BBL/MMCF of raw gas. Gas properties were obtained from gas analyses conducted on samples from the Parknook-3 well.

**Palmerston**

Possible undeveloped reserves have been assigned to the untested gas pay indicated on logs for the Lower Tinowon Formation. Reserves have been determined using probabilistic analysis; however, they correspond to wellbore parameters determined from log analysis, a drainage area of 400 acres and a 60 percent recovery factor as shown in Table 2.1.

Condensate reserves have been assigned to the Lower Tinowon Formation using an expected yield of 27 BBL/MMCF of raw gas. Gas properties were obtained from a gas analysis conducted on samples from the Churchie-1 well.

# PRODUCTION AND DEVELOPMENT FORECAST

## Weribone

It is expected that the coiled tubing unit will be available to drill through the Showgrounds and Basal Rewan Formations in the Weribone-2 well in April. The well will be tied in to Origin's gathering system in the Parknook Field and is forecast to be placed on production by July 1, 2004. Initial gas production rates from the Showgrounds and Basal Rewan Formations are expected to be 2.0 and 1.0 MMCFD, respectively. Production is forecast to decline exponentially from the initial rate to depletion of the assigned reserves.

The well Weribone-3 is scheduled to be drilled and placed on production by July 1, 2005.

## Palmerston

The Palmerston-1 well is expected to be completed in 2004. The well will be tied in to Origin's gathering system and is forecast to be placed on production by April 1, 2005. The initial gas production rate from the Lower Tinowon Formation is expected to be 2.0 MMCFD. Production is forecast to decline exponentially from the initial rate to depletion of the assigned reserves.

# ECONOMIC ANALYSIS

A summary of economic parameters used in this evaluation, including product pricing, operating expenses and capital costs is provided in Table 4. Operating costs were based on estimates provided by Origin.

The current gas price in the Surat Basin is approximately $2.80 AU/GJ. The gas price has been adjusted for heating values and an estimated fee of $1.35 AU/MCF has been subtracted for transportation, compression and processing fees to obtain the wellhead price. The condensate price is currently equivalent to the Malaysian Tapis crude oil price less $2.00 US/BBL. As the Tapis crude tracks fairly close to West Texas Intermediate (WTI), GLJ has forecast condensate prices as WTI less $2.00 US/BBL. Pipeline tariffs and trucking costs for condensate total $8.72 AU/BBL.

Production is subject to a royalty to the Queensland government based on 10 percent of the value of the products at the wellhead. Additional encumbrances on ATP 470P include a net profits interest of 7.5 percent on 100 percent of production and a gross overriding royalty of 1.6 percent on 40 percent of production.

Economic forecasts for each of the reserves categories have been included in the Economic Forecasts section of this report.

***Other Economic Considerations***

This report does not address the following issues:

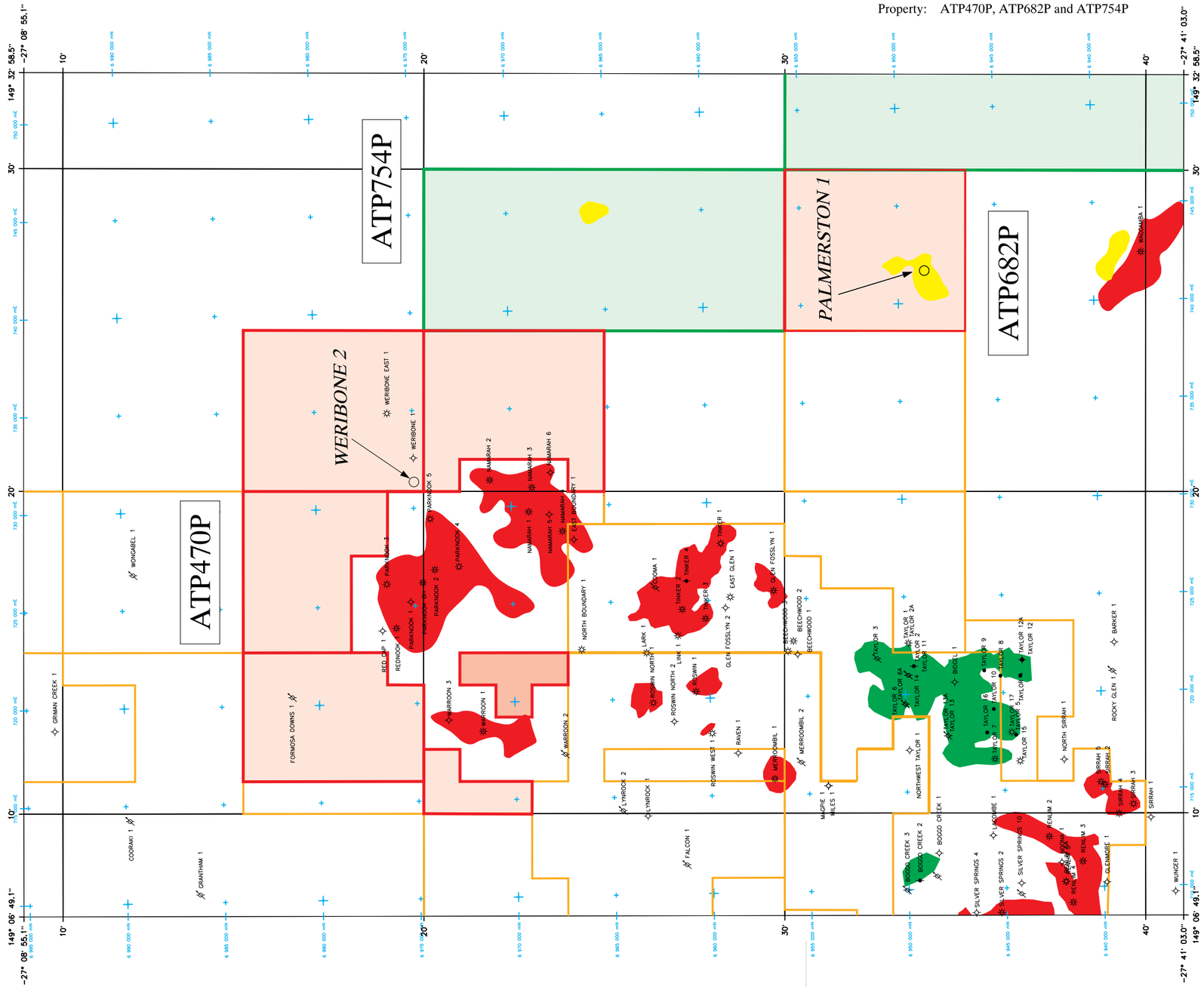
- Facility abandonment/salvage including possible environmental concerns.
- Potential processing income.
- The current condition of field, gathering and processing facilities, i.e. an inspection was not carried out.

Map 1

# Land Map
## Land Blocks, Fields and Wells
## Queensland, Australia

Company: AusAm Resources Limited
Property: ATP470P, ATP682P and ATP754P

Effective Date: March 31, 2004
Scale: 1:225,000 s1046451/aabm01



**“Maps 2, 3 and 4 Available on Request”**

# TABLE 1

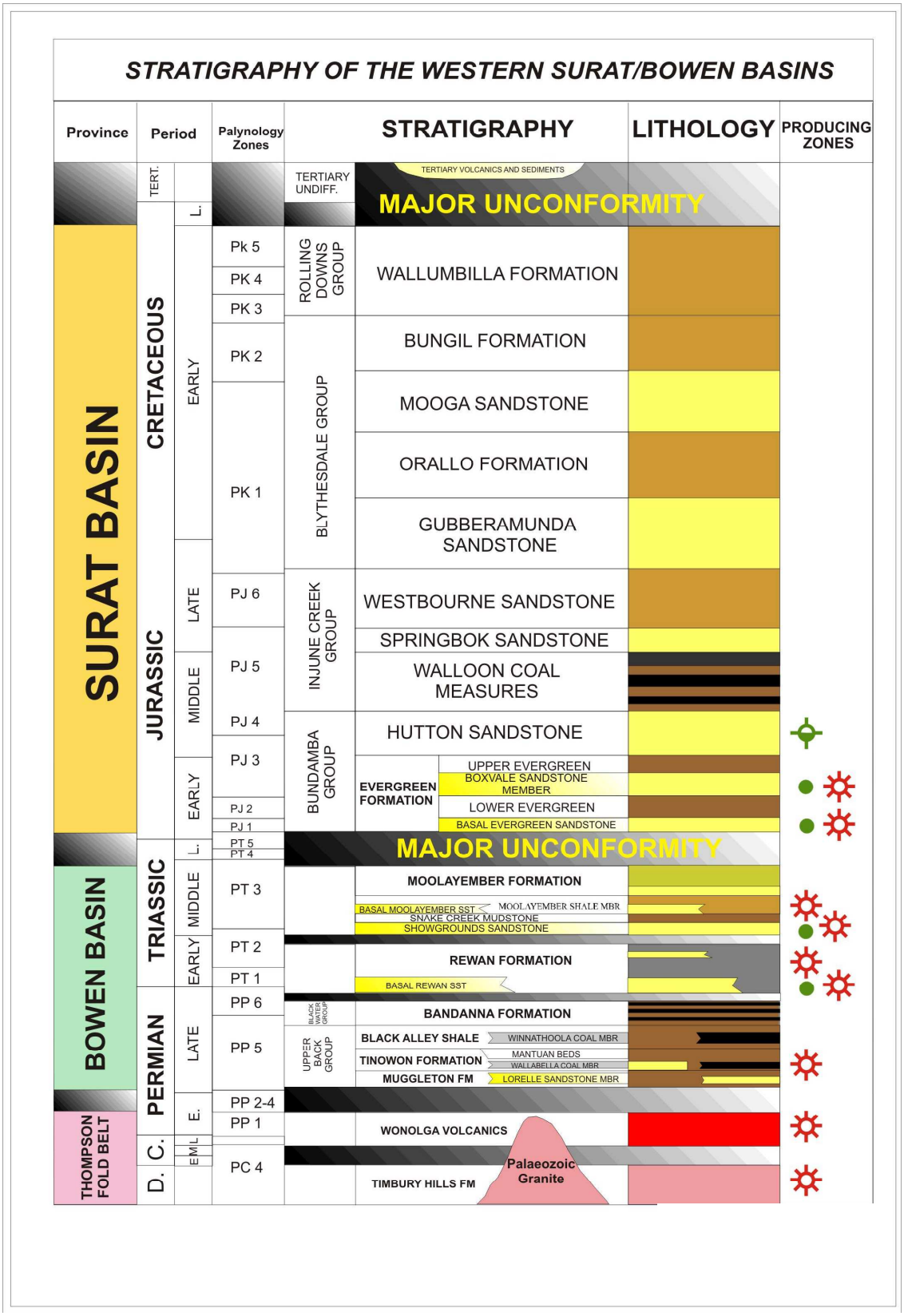

STRATIGRAPHY OF THE WESTERN SURAT/BOWEN BASINS
Province
Period
Palynology Zones
STRATIGRAPHY
LITHOLOGY
PRODUCING ZONES
SURAT BASIN
BOWEN BASIN
THOMPSON FOLD BELT
TERT.
CRETACEOUS
JURASSIC
TRIASSIC
PERMIAN
L.
EARLY
MIDDLE
LATE
E.
EM L
D. C.
TERTIARY UNDIFF.
TERTIARY VOLCANICS AND SEDIMENTS
MAJOR UNCONFORMITY
Pk 5
PK 4
PK 3
PK 2
PK 1
PJ 6
PJ 5
PJ 4
PJ 3
PJ 2
PJ 1
PT 5
PT 4
PT 3
PT 2
PT 1
PP 6
PP 5
PP 2-4
PP 1
PC 4
ROLLING DOWNS GROUP
WALLUMBILLA FORMATION
BLYTHESDALE GROUP
BUNGIL FORMATION
MOOGA SANDSTONE
ORALLO FORMATION
GUBBERAMUNDA SANDSTONE
INJUNE CREEK GROUP
WESTBOURNE SANDSTONE
SPRINGBOK SANDSTONE
WALLOON COAL MEASURES
BUNDAMBA GROUP
HUTTON SANDSTONE
EVERGREEN FORMATION
UPPER EVERGREEN
BOXVALE SANDSTONE MEMBER
LOWER EVERGREEN
BASAL EVERGREEN SANDSTONE
MAJOR UNCONFORMITY
MOOLAYEMBER FORMATION
BASAL MOOLAYEMBER SST
MOOLAYEMBER SHALE MBR
SNAKE CREEK MUDSTONE
SHOWGROUNDS SANDSTONE
REWAN FORMATION
BASAL REWAN SST
BLACK WATER GROUP
BANDANNA FORMATION
UPPER BACK GROUP
BLACK ALLEY SHALE
WINNATHOOLA COAL MBR
TINOWON FORMATION
MANTUAN BEDS
WALLABELLA COAL MBR
MUGGLETON FM
LORELLE SANDSTONE MBR
WONOLGA VOLCANICS
Palaeozoic Granite
TIMBURY HILLS FM

**Table 2**

# Gross Lease Reserves Summary

Company: **AusAm Resources Limited**
Property: **Queensland**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2004-04) Full Year**
Effective Date: **March 31, 2004**

| | | | Oil Mbbl | | | Non-Associated Gas Mmcf | | | | Other Remaining Marketable Reserves | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Reserve Entity | Zone | Methodology | Initial Reserves | Cumulative Production | Remaining Reserves | Initial Reserves | Cumulative Production | Remaining Raw | Remaining Sales | Sol'n Gas Mmcf | Cond Mbbl | LPG Mbbl | Sulphur Mlt |
| Total Proved Plus Probable | | | | | | | | | | | | | |
| ***Palmerston*** | | | | | | | | | | | | | |
| ***Total Palmerston*** | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ***Weribone*** | | | | | | | | | | | | | |
| ***Weribone 2*** | | | | | | | | | | | | | |
| Basal Rewan | Basal Rewan | Vol | 0 | 0 | 0 | 1031 | 0 | 1031 | 980 | 0 | 8 | 0 | 0 |
| Showgrounds | Showgrounds | Vol | 0 | 0 | 0 | 2294 | 0 | 2294 | 2180 | 0 | 18 | 0 | 0 |
| ***Total Weribone 2*** | | | 0 | 0 | 0 | 3326 | 0 | 3325 | 3159 | 0 | 27 | 0 | 0 |
| ***Weribone 3*** | | | | | | | | | | | | | |
| ***Total Weribone 3*** | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ***Total Weribone*** | | | 0 | 0 | 0 | 3326 | 0 | 3325 | 3159 | 0 | 27 | 0 | 0 |
| ***Total Proved Plus Probable*** | | | 0 | 0 | 0 | 3326 | 0 | 3325 | 3159 | 0 | 27 | 0 | 0 |
| Total PPP | | | | | | | | | | | | | |
| ***Palmerston*** | | | | | | | | | | | | | |
| Palmerston-1 | Lower Tinowon | Vol | 0 | 0 | 0 | 1362 | 0 | 1362 | 1294 | 0 | 37 | 0 | 0 |
| ***Total Palmerston*** | | | 0 | 0 | 0 | 1362 | 0 | 1362 | 1294 | 0 | 37 | 0 | 0 |
| ***Weribone*** | | | | | | | | | | | | | |
| ***Weribone 2*** | | | | | | | | | | | | | |
| Basal Rewan | Basal Rewan | Vol | 0 | 0 | 0 | 1031 | 0 | 1031 | 980 | 0 | 8 | 0 | 0 |
| Showgrounds | Showgrounds | Vol | 0 | 0 | 0 | 2294 | 0 | 2294 | 2180 | 0 | 18 | 0 | 0 |

# Gross Lease Reserves Summary

| Reserve Entity | Zone | Methodology | Oil Mbbl | | | Non-Associated Gas Mmcf | | | | Other Remaining Marketable Reserves | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Initial Reserves | Cumulative Production | Remaining Reserves | Initial Reserves | Cumulative Production | Remaining Raw | Remaining Sales | Sol'n Gas Mmcf | Cond Mbbl | LPG Mbbl | Sulphur Mlt |
| ***Total Weribone 2*** | | | 0 | 0 | 0 | 3326 | 0 | 3325 | 3159 | 0 | 27 | 0 | 0 |
| ***Weribone 3*** | | | | | | | | | | | | | |
| Weribone-3 Basal Rewan | Basal Rewan | Vol | 0 | 0 | 0 | 902 | 0 | 902 | 857 | 0 | 7 | 0 | 0 |
| Weribone-3 Showgrounds | Showgrounds | Vol | 0 | 0 | 0 | 2008 | 0 | 2007 | 1907 | 0 | 16 | 0 | 0 |
| ***Total Weribone 3*** | | | 0 | 0 | 0 | 2910 | 0 | 2910 | 2764 | 0 | 23 | 0 | 0 |
| ***Total Weribone*** | | | 0 | 0 | 0 | 6235 | 0 | 6235 | 5924 | 0 | 50 | 0 | 0 |
| ***Total PPP*** | | | 0 | 0 | 0 | 7597 | 0 | 7597 | 7217 | 0 | 87 | 0 | 0 |

p:/s1046451/rems/econ/GLJ_2004-04_Full_Year/Queensland_Table_2_RC00_ult.htm

**Table 2.1**

Company: **AusAm Resources Limited** Effective Date: **March 31, 2004**
Property: **Queensland**

## Gas Reservoir Parameters

| Resource Entity | Zone | Method | RC | Area acre | Net Pay ft | Porosity % | Water Sat'n % | Resid Oil Sat'n % | Original Pressure psi | Reservoir Temp. oR | Zi Factor | Original Gas In Place MMcf | Recovery Factor % | Recoverable Raw Gas MMcf | Cum Production 2004-03-31 MMcf | Remaining Raw Gas 2004-03-31 MMcf | Surface Loss % | Remaining Sales Gas MMcf |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total Proved Plus Probable** | | | | | | | | | | | | | | | | | | |
| Weribone-2 | | | | | | | | | | | | | | | | | | |
| Weribone-2 Basal Rewan | Basal Rewan | Vol | E2 | 400 | 7.5 | 13.7 | 60.0 | - | 3,150 | 632 | 0.860 | 1,473 | 70.0 | 1,031 | - | 1,031 | 5.0 | 980 |
| Weribone-2 Showgrounds | Showgrounds | Vol | E2 | 400 | 14.4 | 12.7 | 50.0 | - | 3,150 | 632 | 0.860 | 3,278 | 70.0 | 2,294 | - | 2,294 | 5.0 | 2,180 |
| **Total : Total Proved Plus Probable** | | | | | | | | | | | | | | **3,325** | **0** | **3,325** | **5.0** | **3,159** |
| **Total PPP** | | | | | | | | | | | | | | | | | | |
| Palmerston-1 | Lower Tinowon | Vol | N2 | 400 | 7.5 | 12.0 | 50.0 | - | 5,336 | 645 | 1.020 | 2,270 | 60.0 | 1,362 | - | 1,362 | 5.0 | 1,294 |
| Weribone-2 | | | | | | | | | | | | | | | | | | |
| Weribone-2 Basal Rewan | Basal Rewan | Vol | E2 | 400 | 7.5 | 13.7 | 60.0 | - | 3,150 | 632 | 0.860 | 1,473 | 70.0 | 1,031 | - | 1,031 | 5.0 | 980 |
| Weribone-2 Showgrounds | Showgrounds | Vol | E2 | 400 | 14.4 | 12.7 | 50.0 | - | 3,150 | 632 | 0.860 | 3,278 | 70.0 | 2,294 | - | 2,294 | 5.0 | 2,180 |
| Weribone-3 | | | | | | | | | | | | | | | | | | |
| Weribone-3 Basal Rewan | Basal Rewan | Vol | N2 | 350 | 7.5 | 13.7 | 60.0 | - | 3,150 | 632 | 0.860 | 1,289 | 70.0 | 902 | - | 902 | 5.0 | 857 |
| Weribone-3 Showgrounds | Showgrounds | Vol | N2 | 350 | 14.4 | 12.7 | 50.0 | - | 3,150 | 632 | 0.860 | 2,868 | 70.0 | 2,007 | - | 2,007 | 5.0 | 1,907 |
| **Total : Total PPP** | | | | | | | | | | | | | | **7,597** | **0** | **7,597** | **5.0** | **7,217** |

The reserves calculated above may not match the economic forecasts due to economic limit considerations.

**Glossary**
E2 : Probable Undeveloped
N2 : Possible Undeveloped

**Table 2.2**

Company: **AusAm Resources Limited**
Property: **Parknook-Namarah**

Reserve Class: **Proved**
Development Class: **Producing**
Effective Date: **March 31, 2004**

## Gas Reservoir Parameters

| Resource Entity | Zone | Method | RC | Area acre | Net Pay ft | Porosity % | Water Sat'n % | Resid Oil Sat'n % | Original Pressure psi | Reservoir Temp. oR | Zi Factor | Original Gas In Place MMcf | Recovery Factor % | Recoverable Raw Gas MMcf | Cum Production 2004-03-31 MMcf | Remaining Raw Gas 2004-03-31 MMcf | Surface Loss % | Remaining Sales Gas MMcf |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Parknook-Namarah** | | | | | | | | | | | | | | | | | | |
| NAMARAH-3 | Basal Rewan | Dec,Vol | A | 55 | 19.7 | 12.0 | 52.0 | - | 3,140 | 632 | 0.862 | 554 | 70.0 | 388 | 388 | 0 | - | 0 |
| NAMARAH-4 | Showgrounds | Dec,Vol | A | 318 | 8.2 | 14.6 | 34.0 | - | 3,140 | 632 | 0.873 | 2,214 | 70.0 | 1,550 | 1,527 | 23 | - | 23 |
| PARKNOOK-2 RW | Basal Rewan | Dec,Vol | A | 193 | 4.9 | 12.5 | 63.0 | - | 3,140 | 632 | 0.873 | 386 | 70.0 | 270 | 217 | 53 | - | 53 |
| PARKNOOK-3 RW | Basal Rewan | Dec,Vol | A | 1,156 | 5.9 | 13.7 | 40.0 | - | 3,140 | 632 | 0.862 | 5,000 | 70.0 | 3,500 | 3,329 | 171 | - | 171 |
| PARKNOOK-3 SG | Showgrounds | Dec,Vol | A | 337 | 13.1 | 13.1 | 44.0 | - | 3,140 | 632 | 0.862 | 2,886 | 70.0 | 2,021 | 1,604 | 417 | - | 417 |
| PARKNOOK-4 SG | Showgrounds | Dec,Vol | A | 7 | 9.5 | 16.9 | 39.0 | - | 3,140 | 632 | 0.873 | 58 | 70.0 | 41 | 41 | 0 | - | 0 |
| PARKNOOK-5 RW | Basal Rewan | Dec,Vol | A | 6 | 8.9 | 13.5 | 61.0 | - | 3,140 | 632 | 0.873 | 27 | 70.0 | 19 | 19 | 0 | - | 0 |
| PARKNOOK-6 RW | Basal Rewan | Dec,Vol | A | 242 | 4.9 | 12.5 | 60.0 | - | 3,140 | 632 | 0.862 | 529 | 70.0 | 370 | 354 | 16 | - | 16 |
| **Total : Parknook-Namarah** | | | | | | | | | | | | | | **8,158** | **7,477** | **680** | **0.0** | **680** |

The reserves calculated above may not match the economic forecasts due to economic limit considerations.

**Glossary**
A : Proved Producing

**Table 3**

# Daily Gross Lease Sales Gas Production (Mcf)

Company: **AusAm Resources Limited**
Property: **Queensland**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2004-04) Full Year**
Effective Date: **March 31, 2004**

| Entity Description | | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | Totals (Mmcf) Subtotal | Remainder | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Proved Plus Probable | | | | | | | | | | | | | | | | |
| ***Palmerston*** | | | | | | | | | | | | | | | | |
| ***Weribone*** | | | | | | | | | | | | | | | | |
| ***Weribone 2*** | | | | | | | | | | | | | | | | |
| Basal Rewan | Basal Rewan | 587 | 681 | 487 | 348 | 249 | 177 | 127 | 90 | 65 | 20 | 0 | 0 | 980 | 0 | 980 |
| Showgrounds | Showgrounds | 1182 | 1397 | 1024 | 751 | 552 | 404 | 296 | 217 | 159 | 117 | 85 | 63 | 2173 | 7 | 2180 |
| ***Total Weribone 2*** | | 1770 | 2078 | 1511 | 1099 | 801 | 581 | 423 | 307 | 224 | 137 | 85 | 63 | 3152 | 7 | 3159 |
| ***Weribone 3*** | | | | | | | | | | | | | | | | |
| ***Total Weribone*** | | 1770 | 2078 | 1511 | 1099 | 801 | 581 | 423 | 307 | 224 | 137 | 85 | 63 | 3152 | 7 | 3159 |
| ***Total Proved Plus Probable*** | | 1770 | 2078 | 1511 | 1099 | 801 | 581 | 423 | 307 | 224 | 137 | 85 | 63 | 3152 | 7 | 3159 |
| Total PPP | | | | | | | | | | | | | | | | |
| ***Palmerston*** | | | | | | | | | | | | | | | | |
| Palmerston-1 | Lower Tinowon | 0 | 1200 | 1048 | 647 | 400 | 246 | 3 | 0 | 0 | 0 | 0 | 0 | 1294 | 0 | 1294 |
| ***Total Palmerston*** | | 0 | 1200 | 1048 | 647 | 400 | 246 | 3 | 0 | 0 | 0 | 0 | 0 | 1294 | 0 | 1294 |
| ***Weribone*** | | | | | | | | | | | | | | | | |
| ***Weribone 2*** | | | | | | | | | | | | | | | | |
| Basal Rewan | Basal Rewan | 587 | 681 | 487 | 348 | 249 | 177 | 127 | 90 | 65 | 20 | 0 | 0 | 980 | 0 | 980 |
| Showgrounds | Showgrounds | 1182 | 1397 | 1024 | 751 | 552 | 404 | 296 | 217 | 159 | 117 | 85 | 63 | 2173 | 7 | 2180 |
| ***Total Weribone 2*** | | 1770 | 2078 | 1511 | 1099 | 801 | 581 | 423 | 307 | 224 | 137 | 85 | 63 | 3152 | 7 | 3159 |
| ***Weribone 3*** | | | | | | | | | | | | | | | | |
| Weribone-3 Basal Rewan | Basal Rewan | 0 | 435 | 650 | 443 | 302 | 205 | 140 | 95 | 65 | 14 | 0 | 0 | 857 | 0 | 857 |

**Table 3**

# Daily Gross Lease Sales Gas Production (Mcf)

| Entity Description | | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | Totals (Mmcf) Subtotal | Remainder | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Weribone-3 Showgrounds | Showgrounds | 0 | 877 | 1338 | 939 | 660 | 461 | 324 | 227 | 160 | 112 | 78 | 50 | 1907 | 0 | 1907 |
| ***Total Weribone 3*** | | 0 | 1312 | 1988 | 1381 | 962 | 666 | 463 | 322 | 224 | 126 | 78 | 50 | 2764 | 0 | 2764 |
| ***Total Weribone*** | | 1770 | 3390 | 3499 | 2480 | 1763 | 1247 | 886 | 630 | 449 | 263 | 164 | 113 | 5916 | 7 | 5924 |
| ***Total PPP*** | | 1770 | 4591 | 4547 | 3127 | 2163 | 1493 | 889 | 630 | 449 | 263 | 164 | 113 | 7210 | 7 | 7217 |

p:/s1046451/rems/econ/GLJ_2004-04_Full_Year/Queensland_Table_3_RC00_glg.htm

**Table 3.1**

# Company Daily Gas Production (Mcf)

Company: **AusAm Resources Limited**
Property: **Queensland**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2004-04) Full Year**
Effective Date: **March 31, 2004**

| Entity Description | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | Totals (Mmcf) Subtotal | Remainder | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Proved Plus Probable | | | | | | | | | | | | | | | |
| ***Palmerston*** | | | | | | | | | | | | | | | |
| ***Weribone*** | | | | | | | | | | | | | | | |
| ***Weribone 2*** | | | | | | | | | | | | | | | |
| Basal Rewan | 244 | 283 | 202 | 144 | 103 | 74 | 53 | 38 | 27 | 8 | 0 | 0 | 407 | 0 | 407 |
| Showgrounds | 491 | 580 | 425 | 312 | 229 | 167 | 123 | 90 | 66 | 48 | 35 | 26 | 902 | 3 | 905 |
| ***Total Weribone 2*** | 734 | 862 | 627 | 456 | 332 | 241 | 175 | 128 | 93 | 57 | 35 | 26 | 1308 | 3 | 1311 |
| ***Weribone 3*** | | | | | | | | | | | | | | | |
| ***Total Weribone*** | 734 | 862 | 627 | 456 | 332 | 241 | 175 | 128 | 93 | 57 | 35 | 26 | 1308 | 3 | 1311 |
| ***Total Proved Plus Probable*** | 734 | 862 | 627 | 456 | 332 | 241 | 175 | 128 | 93 | 57 | 35 | 26 | 1308 | 3 | 1311 |
| Total PPP | | | | | | | | | | | | | | | |
| ***Palmerston*** | | | | | | | | | | | | | | | |
| Palmerston-1 | 0 | 300 | 262 | 162 | 100 | 62 | 1 | 0 | 0 | 0 | 0 | 0 | 323 | 0 | 323 |
| ***Total Palmerston*** | 0 | 300 | 262 | 162 | 100 | 62 | 1 | 0 | 0 | 0 | 0 | 0 | 323 | 0 | 323 |
| ***Weribone*** | | | | | | | | | | | | | | | |
| ***Weribone 2*** | | | | | | | | | | | | | | | |
| Basal Rewan | 264 | 306 | 219 | 156 | 112 | 80 | 57 | 41 | 29 | 9 | 0 | 0 | 441 | 0 | 441 |
| Showgrounds | 532 | 629 | 461 | 338 | 248 | 182 | 133 | 98 | 72 | 52 | 38 | 28 | 978 | 3 | 981 |
| ***Total Weribone 2*** | 796 | 935 | 680 | 494 | 360 | 261 | 190 | 138 | 101 | 62 | 38 | 28 | 1418 | 3 | 1422 |
| ***Weribone 3*** | | | | | | | | | | | | | | | |
| Weribone-3 Basal Rewan | 0 | 196 | 292 | 199 | 136 | 92 | 63 | 43 | 29 | 6 | 0 | 0 | 386 | 0 | 386 |

# Company Daily Gas Production (Mcf)

| Entity Description | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | Totals (Mmcf) Subtotal | Remainder | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Weribone-3 Showgrounds | 0 | 395 | 602 | 422 | 297 | 208 | 146 | 102 | 72 | 50 | 35 | 23 | 858 | 0 | 858 |
| ***Total Weribone 3*** | 0 | 591 | 894 | 621 | 433 | 300 | 208 | 145 | 101 | 57 | 35 | 23 | 1244 | 0 | 1244 |
| ***Total Weribone*** | 796 | 1526 | 1574 | 1116 | 793 | 561 | 399 | 283 | 202 | 118 | 74 | 51 | 2662 | 3 | 2666 |
| ***Total PPP*** | 796 | 1826 | 1836 | 1278 | 893 | 623 | 399 | 283 | 202 | 118 | 74 | 51 | 2986 | 3 | 2989 |

p:/s1046451/rems/econ/GLJ_2004-04_Full_Year/Queensland_Table_3.1_RC00_gas.htm

**Table 4**

**Company: Ausam Resources Limited** **Effective Date: March 31, 2004**
**Property: Surat Basin**

## Economic Parameters

### A) Price Forecasts and By-Product Data

Gilbert Laustsen Jung (2004-04)

| | | | |
|---|---|---|---|
| Sales Gas Heat Content: | Palmerston | 1180 | BTU/SCF |
| | Weribone | 1140 | BTU/SCF |
| Liquid Yields: | Palmerston | 27 | BBL/MMCF |
| | Weribone | 8 | BBL/MMCF |
| Surface Loss: | | 5.0% | |

### B) Operating Costs (2004 Dollars)

Fixed Well Costs: $1,000 /well/month

Gathering Transportation and Processing Costs:

| | | |
|---|---|---|
| Gas: | 1.35 | $/MCF |
| Condensate: | 8.72 | $/BBL |

Note: Gathering transportation and processing costs are deducted from the product price.

### C) Abandonment Costs (2004 Dollars)

Well Abandonment Cost: $100,000 /well

### D) Capital Costs (2004 Dollars)

| | | | Gross Capital Expenditures ($M) | | |
|---|---|---|---|---|---|
| Year | Well/Area | Development Description | Development | Gathering | Total |
| **Probable Undeveloped** | | | | | |
| 2004 | Weribone-2 | Drill Underbalanced & Tie-In | 1000 | 400 | 1400 |
| **Possible Undeveloped** | | | | | |
| 2004 | Palmerston-1 | Completion | 300 | 0 | 300 |
| 2005 | Palmerston-1 | Tie-in Well to Gathering System | | 500 | 500 |
| | Weribone-3 | Drill, Complete & Tie-In | 1750 | 400 | 2150 |

# Economic Forecast

Company: **AusAm Resources Limited**
Property: **Queensland**

Reserve Class: **Proved Plus Probable**
Development Class: **Total**
Pricing: **GLJ (2004-04) Full Year**
Effective Date: **March 31, 2004**

## PRODUCTION FORECAST

| | | Residue Gas Production | | | | | Condensate Production | | | | | Total Oil Equiv. Production | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Gross Gas Wells | Gross Daily Mcf | Compny Daily Mcf | Compny Yearly Mmcf | Net Yearly Mmcf | Price $/Mcf | Gross Daily Stb | Compny Daily Stb | Compny Yearly Stb | Net Yearly Stb | Price $/Bbl | Gross Daily Stb | Compny Daily Stb | Compny Yearly Stb | Net Yearly Stb | Price $/BOE |
| 2004 | 1 | 1770 | 734 | 201 | 180 | 2.01 | 15 | 6 | 1693 | 1513 | 33.16 | 310 | 129 | 35199 | 31454 | 13.07 |
| 2005 | 1 | 2078 | 862 | 315 | 281 | 2.04 | 17 | 7 | 2651 | 2369 | 26.21 | 364 | 151 | 55112 | 49248 | 12.91 |
| 2006 | 1 | 1511 | 627 | 229 | 205 | 2.08 | 13 | 5 | 1927 | 1722 | 23.49 | 265 | 110 | 40072 | 35809 | 13.01 |
| 2007 | 1 | 1099 | 456 | 166 | 149 | 2.11 | 9 | 4 | 1402 | 1252 | 20.75 | 192 | 80 | 29141 | 26040 | 13.05 |
| 2008 | 1 | 801 | 332 | 121 | 108 | 2.14 | 7 | 3 | 1022 | 913 | 20.61 | 140 | 58 | 21244 | 18984 | 13.21 |
| 2009 | 1 | 581 | 241 | 88 | 79 | 2.17 | 5 | 2 | 741 | 662 | 20.48 | 102 | 42 | 15404 | 13765 | 13.38 |
| 2010 | 1 | 423 | 175 | 64 | 57 | 2.20 | 4 | 1 | 539 | 482 | 20.99 | 74 | 31 | 11207 | 10015 | 13.57 |
| 2011 | 1 | 307 | 128 | 47 | 42 | 2.24 | 3 | 1 | 392 | 350 | 21.16 | 54 | 22 | 8155 | 7287 | 13.81 |
| 2012 | 1 | 224 | 93 | 34 | 30 | 2.27 | 2 | 1 | 286 | 256 | 21.67 | 39 | 16 | 5948 | 5315 | 14.01 |
| 2013 | 1 | 137 | 57 | 21 | 19 | 2.30 | 1 | 0 | 175 | 156 | 21.85 | 24 | 10 | 3631 | 3244 | 14.19 |
| 2014 | 1 | 85 | 35 | 13 | 12 | 2.34 | 1 | 0 | 109 | 97 | 22.35 | 15 | 6 | 2267 | 2026 | 14.44 |
| 2015 | 1 | 63 | 26 | 9 | 8 | 2.38 | 1 | 0 | 80 | 71 | 22.69 | 11 | 5 | 1662 | 1486 | 14.66 |
| Sub. | 1 | 735 | 305 | 1308 | 1169 | 2.10 | 6 | 3 | 11016 | 9844 | 24.52 | 129 | 53 | 229042 | 204672 | 13.17 |
| Rem. | 1 | 50 | 21 | 3 | 3 | 2.39 | 0 | 0 | 25 | 22 | 22.81 | 9 | 4 | 510 | 456 | 14.74 |
| **Tot.** | **1** | **713** | **296** | **1311** | **1172** | **2.10** | **6** | **2** | **11041** | **9866** | **24.51** | **125** | **52** | **229552** | **205128** | **13.18** |

## REVENUE AND EXPENSE FORECAST

| | Revenue Before Burdens | | | | | | Royalty Burdens Pre-Processing | | Gas Processing Allowance | | Total Royalty After Process. | Net Revenue After Royalty | Operating Expenses | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Working Interest | | | | | | | | | | | | | |
| Year | Oil M$ | Gas M$ | NGL+Sul M$ | Total M$ | Royalty Interest M$ | Company Total M$ | Crown M$ | Other M$ | Crown M$ | Other M$ | M$ | M$ | Fixed M$ | Variable M$ | Total M$ |
| 2004 | 0 | 404 | 56 | 460 | 0 | 460 | 46 | 3 | 0 | 0 | 49 | 411 | 1 | 0 | 1 |
| 2005 | 0 | 642 | 69 | 712 | 0 | 712 | 71 | 5 | 0 | 0 | 76 | 636 | 5 | 0 | 5 |
| 2006 | 0 | 476 | 45 | 521 | 0 | 521 | 52 | 3 | 0 | 0 | 55 | 466 | 5 | 0 | 5 |
| 2007 | 0 | 351 | 29 | 380 | 0 | 380 | 38 | 2 | 0 | 0 | 40 | 340 | 5 | 0 | 5 |
| 2008 | 0 | 260 | 21 | 281 | 0 | 281 | 28 | 2 | 0 | 0 | 30 | 251 | 5 | 0 | 5 |
| 2009 | 0 | 191 | 15 | 206 | 0 | 206 | 21 | 1 | 0 | 0 | 22 | 184 | 5 | 0 | 5 |
| 2010 | 0 | 141 | 11 | 152 | 0 | 152 | 15 | 1 | 0 | 0 | 16 | 136 | 5 | 0 | 5 |
| 2011 | 0 | 104 | 8 | 113 | 0 | 113 | 11 | 1 | 0 | 0 | 12 | 101 | 6 | 0 | 6 |
| 2012 | 0 | 77 | 6 | 83 | 0 | 83 | 8 | 1 | 0 | 0 | 9 | 74 | 6 | 0 | 6 |
| 2013 | 0 | 48 | 4 | 52 | 0 | 52 | 5 | 0 | 0 | 0 | 5 | 46 | 6 | 0 | 6 |
| 2014 | 0 | 30 | 2 | 33 | 0 | 33 | 3 | 0 | 0 | 0 | 3 | 29 | 6 | 0 | 6 |
| 2015 | 0 | 23 | 2 | 24 | 0 | 24 | 2 | 0 | 0 | 0 | 3 | 22 | 6 | 0 | 6 |
| Sub. | 0 | 2747 | 270 | 3017 | 0 | 3017 | 302 | 19 | 0 | 0 | 321 | 2696 | 61 | 0 | 61 |
| Rem. | 0 | 7 | 1 | 8 | 0 | 8 | 1 | 0 | 0 | 0 | 1 | 7 | 2 | 0 | 2 |
| **Tot.** | **0** | **2754** | **271** | **3024** | **0** | **3024** | **302** | **19** | **0** | **0** | **322** | **2703** | **64** | **0** | **64** |
| Disc | 0 | 2097 | 213 | 2310 | 0 | 2310 | 231 | 15 | 0 | 0 | 246 | 2064 | 36 | 0 | 36 |

| | Other Expenses | | | Net Prod'n Revenue | Other Income | | Aband. Costs | Oper. Income | Net Capital Investment | | | | Before Tax Cash Flow | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Mineral Tax M$ | Capital Tax M$ | NPI Payment M$ | M$ | Other M$ | ARTC M$ | M$ | M$ | Dev. M$ | Plant M$ | Tang. M$ | Total M$ | Annual M$ | Cum. M$ | 10% Dcf M$ |
| 2004 | 0 | 0 | 31 | 379 | 0 | 0 | 0 | 379 | 1000 | 400 | 0 | 1400 | -1021 | -1021 | -985 |
| 2005 | 0 | 0 | 47 | 584 | 0 | 0 | 0 | 584 | 0 | 0 | 0 | 0 | 584 | -437 | -467 |
| 2006 | 0 | 0 | 35 | 426 | 0 | 0 | 0 | 426 | 0 | 0 | 0 | 0 | 426 | -11 | -123 |
| 2007 | 0 | 0 | 25 | 309 | 0 | 0 | 0 | 309 | 0 | 0 | 0 | 0 | 309 | 298 | 104 |
| 2008 | 0 | 0 | 18 | 227 | 0 | 0 | 0 | 227 | 0 | 0 | 0 | 0 | 227 | 526 | 256 |
| 2009 | 0 | 0 | 13 | 165 | 0 | 0 | 0 | 165 | 0 | 0 | 0 | 0 | 165 | 691 | 356 |
| 2010 | 0 | 0 | 10 | 121 | 0 | 0 | 0 | 121 | 0 | 0 | 0 | 0 | 121 | 812 | 422 |
| 2011 | 0 | 0 | 7 | 88 | 0 | 0 | 0 | 88 | 0 | 0 | 0 | 0 | 88 | 900 | 466 |
| 2012 | 0 | 0 | 5 | 64 | 0 | 0 | 0 | 64 | 0 | 0 | 0 | 0 | 64 | 963 | 495 |
| 2013 | 0 | 0 | 3 | 37 | 0 | 0 | 0 | 37 | 0 | 0 | 0 | 0 | 37 | 1001 | 511 |
| 2014 | 0 | 0 | 2 | 22 | 0 | 0 | 0 | 22 | 0 | 0 | 0 | 0 | 22 | 1022 | 519 |
| 2015 | 0 | 0 | 1 | 15 | 0 | 0 | 0 | 15 | 0 | 0 | 0 | 0 | 15 | 1037 | 524 |
| Sub. | 0 | 0 | 198 | 2437 | 0 | 0 | 0 | 2437 | 1000 | 400 | 0 | 1400 | 1037 | 1037 | 15 |
| Rem. | 0 | 0 | 0 | 4 | 0 | 0 | 50 | -45 | 0 | 0 | 0 | 0 | -45 | 992 | 992 |
| **Tot.** | **0** | **0** | **198** | **2441** | **0** | **0** | **50** | **2392** | **1000** | **400** | **0** | **1400** | **992** | **992** | **510** |
| Disc | 0 | 0 | 152 | 1876 | 0 | 0 | 15 | 1861 | 965 | 386 | 0 | 1351 | 510 | 510 | 510 |

## RESERVE SUMMARY

| | | Remaining Reserves at April 1, 2004 | | | | | Oil Equivalents | | | Reserve Life Indic. (yr) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Product** | Units | Gross | Working Interest | Roy/NPI Interest | Total Company | Net | BOE Factor | Company Mstb | % of Total | Reserve Life | Life Index | Half Life |
| Residue Gas | Mmcf | 3159 | 1311 | 0 | 1311 | 1172 | 6.000 | 219 | 95 | 12.1 | 4.9 | 2.4 |
| | MMMBtu | 3159 | 1311 | 0 | 1311 | 1172 | | | | 12.1 | 4.9 | 2.4 |
| Condensate | Mstb | 27 | 11 | 0 | 11 | 10 | 1.000 | 11 | 5 | 12.1 | 4.9 | 2.4 |
| Total Oil Eq. | Mstb | 553 | 230 | 0 | 230 | 205 | | 230 | 100 | 12.1 | 4.9 | 2.4 |

## PRODUCT REVENUE AND EXPENSES

| | | Average First Year Unit Values | | | | | | | Net Revenue After Royalties | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Product** | Units | Base Price | Price Adjust. | Wellhead Price | Net Burdens | Operating Expenses | Other Expenses | Prod'n Revenue | Undisc M$ | % of Total | 10% Disc M$ | % of Total |
| Residue Gas | $/Mcf | 2.95 | -0.94 | 2.01 | 0.21 | 0.01 | 0.00 | 1.79 | 2461 | 91 | 1874 | 91 |
| Condensate | $/Stb | 33.16 | 0.00 | 33.16 | 3.53 | 0.09 | 0.00 | 29.54 | 242 | 9 | 191 | 9 |
| Total Oil Eq. | $/BOE | 18.44 | -5.37 | 13.07 | 1.39 | 0.04 | 0.00 | 11.65 | 2703 | 100 | 2064 | 100 |

## INTEREST AND NET PRESENT VALUE SUMMARY

| Revenue Interests and Burdens (%) | | |
|---|---|---|
| | Initial | Average |
| Working Interest | 41.5000 | 41.5000 |
| Capital Interest | 100.0000 | 100.0000 |
| Royalty Interest | 0.0000 | 0.0000 |
| Crown Royalty | 10.0000 | 10.0000 |
| Non-crown Royalty | 0.6400 | 0.6400 |
| Mineral Tax | 0.0000 | 0.0000 |
| NPI Payment | 7.5000 | 7.6437 |

| | Net Present Value Before Income Tax | | | | |
|---|---|---|---|---|---|
| Disc. Rate % | Prod'n Revenue M$ | Operating Income M$ | Capital Invest. M$ | Cash Flow M$ | Cash Flow $/BOE |
| 0.0 | 2441 | 2392 | 1400 | 992 | 4.32 |
| 5.0 | 2121 | 2094 | 1375 | 719 | 3.13 |
| 8.0 | 1967 | 1947 | 1360 | 587 | 2.56 |
| 10.0 | 1876 | 1861 | 1351 | 510 | 2.22 |
| 12.0 | 1794 | 1782 | 1342 | 440 | 1.92 |
| 15.0 | 1684 | 1675 | 1329 | 347 | 1.51 |
| 20.0 | 1530 | 1524 | 1307 | 217 | 0.94 |

Project.....1046451
Entity.....Queensland (Total Proved Plus Probable)
Evaluator...Braaten, Keith M.

# Economic Forecast

Company: **AusAm Resources Limited**
Property: **Queensland**

Reserve Class: **Total**
Development Class: **PPP**
Pricing: **GLJ (2004-04) Full Year**
Effective Date: **March 31, 2004**

## PRODUCTION FORECAST

| | | Residue Gas Production | | | | | Condensate Production | | | | | Total Oil Equiv. Production | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Gross Gas Wells | Gross Daily Mcf | Compny Daily Mcf | Compny Yearly Mmcf | Net Yearly Mmcf | Price $/Mcf | Gross Daily Stb | Compny Daily Stb | Compny Yearly Stb | Net Yearly Stb | Price $/Bbl | Gross Daily Stb | Compny Daily Stb | Compny Yearly Stb | Net Yearly Stb | Price $/BOE |
| 2004 | 1 | 1770 | 796 | 218 | 195 | 2.01 | 15 | 7 | 1836 | 1640 | 33.16 | 310 | 139 | 38167 | 34106 | 13.07 |
| 2005 | 3 | 4591 | 1826 | 666 | 596 | 2.06 | 63 | 21 | 7802 | 6992 | 26.21 | 828 | 326 | 118870 | 106359 | 13.27 |
| 2006 | 3 | 4547 | 1836 | 670 | 600 | 2.10 | 59 | 21 | 7557 | 6770 | 23.49 | 817 | 327 | 119272 | 106700 | 13.27 |
| 2007 | 3 | 3127 | 1278 | 466 | 417 | 2.13 | 39 | 14 | 5108 | 4575 | 20.75 | 560 | 227 | 82831 | 74091 | 13.24 |
| 2008 | 3 | 2163 | 893 | 326 | 292 | 2.15 | 26 | 10 | 3476 | 3113 | 20.61 | 387 | 158 | 57821 | 51715 | 13.38 |
| 2009 | 3 | 1493 | 623 | 227 | 203 | 2.18 | 18 | 6 | 2364 | 2116 | 20.48 | 266 | 110 | 40249 | 35995 | 13.53 |
| 2010 | 3 | 889 | 399 | 146 | 130 | 2.20 | 8 | 3 | 1234 | 1102 | 20.99 | 156 | 70 | 25532 | 22816 | 13.58 |
| 2011 | 2 | 630 | 283 | 103 | 92 | 2.24 | 5 | 2 | 871 | 778 | 21.16 | 110 | 50 | 18105 | 16178 | 13.81 |
| 2012 | 2 | 449 | 202 | 74 | 66 | 2.27 | 4 | 2 | 621 | 555 | 21.67 | 79 | 35 | 12906 | 11532 | 14.01 |
| 2013 | 2 | 263 | 118 | 43 | 39 | 2.30 | 2 | 1 | 364 | 325 | 21.85 | 46 | 21 | 7559 | 6755 | 14.19 |
| 2014 | 2 | 164 | 74 | 27 | 24 | 2.34 | 1 | 1 | 227 | 202 | 22.35 | 29 | 13 | 4710 | 4209 | 14.44 |
| 2015 | 2 | 113 | 51 | 19 | 17 | 2.37 | 1 | 0 | 156 | 139 | 22.67 | 20 | 9 | 3241 | 2896 | 14.65 |
| Sub. | 2 | 1681 | 696 | 2986 | 2670 | 2.12 | 20 | 7 | 31614 | 28309 | 23.51 | 300 | 123 | 529263 | 473353 | 13.37 |
| Rem. | 1 | 50 | 23 | 3 | 3 | 2.39 | 0 | 0 | 27 | 24 | 22.82 | 9 | 4 | 553 | 494 | 14.74 |
| **Tot.** | **2** | **1630** | **675** | **2989** | **2673** | **2.12** | **20** | **7** | **31640** | **28333** | **23.51** | **291** | **120** | **529816** | **473847** | **13.37** |

## REVENUE AND EXPENSE FORECAST

| | Revenue Before Burdens | | | | | | Royalty Burdens Pre-Processing | | Gas Processing Allowance | | Total Royalty After Process. | Net Revenue After Royalty | Operating Expenses | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Working Interest | | | | | | | | | | | | | |
| Year | Oil M$ | Gas M$ | NGL+Sul M$ | Total M$ | Royalty Interest M$ | Company Total M$ | Crown M$ | Other M$ | Crown M$ | Other M$ | M$ | M$ | Fixed M$ | Variable M$ | Total M$ |
| 2004 | 0 | 438 | 61 | 499 | 0 | 499 | 50 | 3 | 0 | 0 | 53 | 446 | 1 | 0 | 1 |
| 2005 | 0 | 1373 | 204 | 1577 | 0 | 1577 | 158 | 8 | 0 | 0 | 166 | 1411 | 11 | 0 | 11 |
| 2006 | 0 | 1406 | 178 | 1583 | 0 | 1583 | 158 | 8 | 0 | 0 | 167 | 1416 | 14 | 0 | 14 |
| 2007 | 0 | 991 | 106 | 1097 | 0 | 1097 | 110 | 6 | 0 | 0 | 116 | 981 | 14 | 0 | 14 |
| 2008 | 0 | 702 | 72 | 774 | 0 | 774 | 77 | 4 | 0 | 0 | 82 | 692 | 15 | 0 | 15 |
| 2009 | 0 | 496 | 48 | 545 | 0 | 545 | 54 | 3 | 0 | 0 | 58 | 487 | 15 | 0 | 15 |
| 2010 | 0 | 321 | 26 | 347 | 0 | 347 | 35 | 2 | 0 | 0 | 37 | 310 | 12 | 0 | 12 |
| 2011 | 0 | 232 | 18 | 250 | 0 | 250 | 25 | 2 | 0 | 0 | 27 | 223 | 12 | 0 | 12 |
| 2012 | 0 | 167 | 13 | 181 | 0 | 181 | 18 | 1 | 0 | 0 | 19 | 162 | 12 | 0 | 12 |
| 2013 | 0 | 99 | 8 | 107 | 0 | 107 | 11 | 1 | 0 | 0 | 11 | 96 | 12 | 0 | 12 |
| 2014 | 0 | 63 | 5 | 68 | 0 | 68 | 7 | 0 | 0 | 0 | 7 | 61 | 13 | 0 | 13 |
| 2015 | 0 | 44 | 4 | 47 | 0 | 47 | 5 | 0 | 0 | 0 | 5 | 42 | 12 | 0 | 12 |
| Sub. | 0 | 6332 | 743 | 7075 | 0 | 7075 | 708 | 39 | 0 | 0 | 747 | 6328 | 143 | 0 | 143 |
| Rem. | 0 | 8 | 1 | 8 | 0 | 8 | 1 | 0 | 0 | 0 | 1 | 7 | 2 | 0 | 2 |
| **Tot.** | **0** | **6339** | **744** | **7083** | **0** | **7083** | **708** | **39** | **0** | **0** | **748** | **6335** | **145** | **0** | **145** |
| Disc | 0 | 4723 | 575 | 5298 | 0 | 5298 | 530 | 29 | 0 | 0 | 559 | 4739 | 84 | 0 | 84 |

| | Other Expenses | | | Net Prod'n Revenue | Other Income | | Aband. Costs | Oper. Income | Net Capital Investment | | | | Before Tax Cash Flow | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Mineral Tax M$ | Capital Tax M$ | NPI Payment M$ | M$ | Other M$ | ARTC M$ | M$ | M$ | Dev. M$ | Plant M$ | Tang. M$ | Total M$ | Annual M$ | Cum. M$ | 10% Dcf M$ |
| 2004 | 0 | 0 | 33 | 411 | 0 | 0 | 0 | 411 | 1075 | 400 | 0 | 1475 | -1064 | -1064 | -1026 |
| 2005 | 0 | 0 | 84 | 1317 | 0 | 0 | 0 | 1317 | 959 | 346 | 0 | 1305 | 12 | -1052 | -1016 |
| 2006 | 0 | 0 | 87 | 1315 | 0 | 0 | 0 | 1315 | 0 | 0 | 0 | 0 | 1315 | 263 | 46 |
| 2007 | 0 | 0 | 62 | 905 | 0 | 0 | 0 | 905 | 0 | 0 | 0 | 0 | 905 | 1169 | 710 |
| 2008 | 0 | 0 | 44 | 633 | 0 | 0 | 0 | 633 | 0 | 0 | 0 | 0 | 633 | 1802 | 1132 |
| 2009 | 0 | 0 | 31 | 441 | 0 | 0 | 0 | 441 | 0 | 0 | 0 | 0 | 441 | 2243 | 1400 |
| 2010 | 0 | 0 | 22 | 276 | 0 | 0 | 27 | 248 | 0 | 0 | 0 | 0 | 248 | 2491 | 1536 |
| 2011 | 0 | 0 | 16 | 196 | 0 | 0 | 0 | 196 | 0 | 0 | 0 | 0 | 196 | 2687 | 1634 |
| 2012 | 0 | 0 | 11 | 138 | 0 | 0 | 0 | 138 | 0 | 0 | 0 | 0 | 138 | 2825 | 1697 |
| 2013 | 0 | 0 | 6 | 77 | 0 | 0 | 0 | 77 | 0 | 0 | 0 | 0 | 77 | 2902 | 1729 |
| 2014 | 0 | 0 | 4 | 45 | 0 | 0 | 0 | 45 | 0 | 0 | 0 | 0 | 45 | 2947 | 1746 |
| 2015 | 0 | 0 | 2 | 28 | 0 | 0 | 53 | -25 | 0 | 0 | 0 | 0 | -25 | 2922 | 1738 |
| Sub. | 0 | 0 | 402 | 5783 | 0 | 0 | 80 | 5702 | 2034 | 746 | 0 | 2780 | 2922 | 2922 | -25 |
| Rem. | 0 | 0 | 0 | 4 | 0 | 0 | 54 | -49 | 0 | 0 | 0 | 0 | -49 | 2873 | 2873 |
| **Tot.** | **0** | **0** | **403** | **5787** | **0** | **0** | **134** | **5653** | **2034** | **746** | **0** | **2780** | **2873** | **2873** | **1722** |
| Disc | 0 | 0 | 300 | 4354 | 0 | 0 | 50 | 4304 | 1889 | 693 | 0 | 2582 | 1722 | 1722 | 1722 |

## RESERVE SUMMARY

| | | Remaining Reserves at April 1, 2004 | | | | | Oil Equivalents | | | Reserve Life Indic. (yr) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Product** | Units | Gross | Working Interest | Roy/NPI Interest | Total Company | Net | BOE Factor | Company Mstb | % of Total | Reserve Life | Life Index | Half Life |
| Residue Gas | Mmcf | 7217 | 2989 | 0 | 2989 | 2673 | 6.000 | 498 | 94 | 12.1 | 10.3 | 2.7 |
| | MMMBtu | 7217 | 2989 | 0 | 2989 | 2673 | | | | 12.1 | 10.3 | 2.7 |
| Condensate | Mstb | 87 | 32 | 0 | 32 | 28 | 1.000 | 32 | 6 | 12.1 | 12.9 | 2.6 |
| Total Oil Eq. | Mstb | 1290 | 530 | 0 | 530 | 474 | | 530 | 100 | 12.1 | 10.4 | 2.7 |

## PRODUCT REVENUE AND EXPENSES

| | | Average First Year Unit Values | | | | | | | Net Revenue After Royalties | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Product** | Units | Base Price | Price Adjust. | Wellhead Price | Net Burdens | Operating Expenses | Other Expenses | Prod'n Revenue | Undisc M$ | % of Total | 10% Disc M$ | % of Total |
| Residue Gas | $/Mcf | 2.95 | -0.94 | 2.01 | 0.21 | 0.01 | 0.00 | 1.79 | 5669 | 89 | 4224 | 89 |
| Condensate | $/Stb | 33.16 | 0.00 | 33.16 | 3.53 | 0.09 | 0.00 | 29.54 | 666 | 11 | 515 | 11 |
| Total Oil Eq. | $/BOE | 18.44 | -5.37 | 13.07 | 1.39 | 0.04 | 0.00 | 11.65 | 6335 | 100 | 4739 | 100 |

## INTEREST AND NET PRESENT VALUE SUMMARY

| Revenue Interests and Burdens (%) | | |
|---|---|---|
| | Initial | Average |
| Working Interest | 45.0000 | 40.7292 |
| Capital Interest | 86.7647 | 63.3360 |
| Royalty Interest | 0.0000 | 0.0000 |
| Crown Royalty | 10.0000 | 10.0000 |
| Non-crown Royalty | 0.6400 | 0.5561 |
| Mineral Tax | 0.0000 | 0.0000 |
| NPI Payment | 7.5000 | 6.6499 |

| | Net Present Value Before Income Tax | | | | |
|---|---|---|---|---|---|
| Disc. Rate % | Prod'n Revenue M$ | Operating Income M$ | Capital Invest. M$ | Cash Flow M$ | Cash Flow $/BOE |
| 0.0 | 5787 | 5653 | 2780 | 2873 | 5.42 |
| 5.0 | 4978 | 4898 | 2676 | 2221 | 4.19 |
| 8.0 | 4585 | 4525 | 2619 | 1907 | 3.60 |
| 10.0 | 4354 | 4304 | 2582 | 1722 | 3.25 |
| 12.0 | 4144 | 4102 | 2547 | 1555 | 2.94 |
| 15.0 | 3861 | 3829 | 2496 | 1333 | 2.52 |
| 20.0 | 3464 | 3442 | 2417 | 1025 | 1.94 |

Project.....1046451
Entity.....Queensland (Total PPP)
Evaluator...Braaten, Keith M.

# AUSAM RESOURCES LIMITED

# ASSESSMENT OF UNDISCOVERED RESOURCES

# QUEENSLAND, AUSTRALIA

**Effective March 31, 2004**

Prepared by
Roger J. Mahoney, P.Geoph.
T. Mark Jobin, P.Geol.
Keith M. Braaten, P.Eng.

**1046451**

# ASSESSMENT OF UNDISCOVERED RESOURCES

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# INTRODUCTION

AusAm Resources Limited (AusAm) retained Gilbert Laustsen Jung Associates Ltd. (GLJ) to prepare an assessment of their undiscovered resources in the Surat/Bowen Basin located in the State of Queensland, Australia. AusAm holds interests in the following permits in the Surat/Bowen Basin:

| Permit | Equity Interest | Area |
|---|---|---|
| ATP 470P | 35%<br>(option to earn up to 45%)<br>excluding PL 71 area | 405 $km^2$<br>(85,000 acres) |
| PL 71 | 0%<br>(pending - option to earn 33%) | 72 $km^2$<br>(15,000 acres) |
| ATP 682P | 25% | 75 $km^2$<br>(18,500 acres) |
| ATP 754P | 50% | 6,102 $km^2$<br>(1,507,000 acres) |
| PL 101 | 0%<br>(pending - option to earn 50%) | 241 $km^2$<br>(60,000 acres) |
| PL 176 | 0%<br>(pending - option to earn 50%) | 213 $km^2$<br>(53,000 acres) |

A number of exploration prospects and leads have been identified on AusAm's acreage in the western Surat/Bowen Basin. Prospects and leads reviewed by GLJ include:

a) Weribone Lead (35% working interest) - Stratigraphic trap identified in the Tinowon Formation to the east of the main Parknook/Weribone structure in ATP 470P.
b) Ungabilla Lead (50% working interest) - Seismically defined undrilled exploration prospect located in ATP 754P just north of the drilled Palmerston 1 well.
c) Farawell North Lead (50% working interest) - Located in ATP 754P.
d) Farawell Prospect (50% working interest) - Located in ATP 754P.
e) Cockatoo Lead (50% working interest) - Located in ATP 754P.
f) Cockatoo North Lead (50% working interest) - Located in ATP 754P.
g) Flinton Lead (50% working interest) - Located in ATP 754P.
h) Flinton South Lead (50% working interest) - Located in ATP 754P.
i) Aurifer Downs Lead (50% working interest) - Located in ATP 754P.

## SUMMARY

GLJ analyzed the potential value of these exploration plays by relating the exploration risk to the potential reward of a discovery. Calculating the expected monetary value of the play is one method that is in common use today.

The expected monetary value was calculated by comparing the risked net present value of a discovery to the risked cost of drilling an abandoned well:

$$EMV = CR \times NPV - (1-CR) \times Aban$$

Where: EMV = Expected Monetary Value
CR = Commercial Risk (Exploration Risk × Commercial Risk)
NPV = Net Present value of the potential discovery
Aban = Abandoned well cost.

In this case, GLJ considers the mean resource estimate in determining the NPV.

The calculated EMV's for all the prospects and leads reviewed by GLJ were negative. The negative EMV values result from the relatively small size of the identified structural prospects and high risk associated with them. The negative EMV's of these prospects and leads reflect, in part the preliminary nature of work done with respect to the Tinowon play on the AusAm acreage to date. It is noted that, with the exception of the Aurifer Downs lead, the identified prospects and leads are within the Priority 1 area in a proposed work program for ATP 754P. This Priority 1 area is believed to be the most prospective in pursuing the Permian Tinowon sandstone play. Extensive geophysical and geological work has been budgeted in this work program. Information from this work will advance the understanding of the Tinowon sandstone play and will be used to high-grade prospective areas for drilling and additional seismic work. Further from this work a ranked prospect and lead inventory will be developed. This additional geophysical and geological analysis may reduce the risk associated with trapping and reservoir rock.

## GEOPHYSICS

AusAm has access to a large grid of seismic data, through the Queensland government, over the area of interest. The bulk of the data was acquired in the late 1970's and 1980's with what can be described as state of the art parameters at that time. The fold of the data was six in the 1970's acquisition, and increased to twelve for the 1980's data. The group intervals employed were larger than would be used today, resulting in a lower dominant frequency on the data, which will make delineation of thin beds more difficult.

The seismic data had not been stored under the best conditions, and this has resulted in deterioration in the quality of the seismic tapes. Some of the tapes suffer from sticktion, the magnetic material peels off when the tapes are being read. In order to read these tapes, they need to be baked prior to loading. If the deterioration is not too severe, baking will work; if the deterioration is too severe, baking will not help. In the case where the original data cannot be reclaimed from the original tapes, then scanning of the paper stacks is undertaken. The scanned data allows some post stack processing to be undertaken, possibly migration and refined filtering. This will improve the final appearance of the data, but is not a good substitute for the missed opportunity to fully reprocess the data. Reprocessing with current software would provide the opportunity to refine the dynamics and the statics; the statics are particularly problematical in the Surat Basin. In the future, when seismically assessing the merits of various structures, the structures defined by reprocessed data should have a higher rating.

At the time of GLJ's visit to Brisbane, a certain amount of seismic interpretation had been carried out. MBA Petroleum Consultants (MBA), on behalf of AusAm, did some preliminary mapping over areas where anomalies had previously been identified. These anomalies were taken off work done by previous operators, and compiled on a regional map. The MBA work showed that some of the anomalies had apparently moved. This is probably the result of different events being used in the respective sets of mapping. MBA used the top Permian, Bandanna coal event to map the structures, and it is possible that the culminations are shifted at different levels. The vertical relief on most of the structures reviewed is small at Bandanna level, in the 20 meter range, so it is quite possible that a small culmination at a different level is located differently.

AusAm's partner, Origin Energy Resources Limited (Origin) has done detailed mapping in the area of the Ungabilla prospect, using a set of reprocessed data. Origin has also done some detailed interpretation and mapping in the Weribone area and the possible east Weribone stratigraphic play in the Upper Tinowon. The basis for interpreting Tinowon to be present was discussed with Origin.

Significantly, the mapping carried out by Origin shows the structural differences that can occur through reprocessing the data with revised statics. Some examples were shown in the Ungabilla area where 2 versions of the same line were compared, before and after revised statics. There were apparent differences in structure, which is important considering the structuring being mapped has low relief. This emphasizes the point that if old, unreprocessed data is used in the mapping, an uncertainty in structural mapping will occur.

GLJ has either mapped or verified the mapping of MBA and Origin over the identified prospects and leads. It is noted that GLJ has determined the vertical closures (in meters) for these prospects and leads by converting time to thickness using a velocity of 3,000 m/sec. The velocity was obtained from the Roccabright #1 well, where a time, depth, velocity cross plot was available. This velocity corresponded approximately to a time of 1.550 seconds and a depth of 2,300 m., and was used for ease of computation.

Identification and areal distribution of the Tinowon Sandstone is one of the main challenges involved in the play. MBA, in their interpretation, has identified character changes at the Tinowon level that could be caused by Tinowon channels. As currently identified, these would be trending approximately N-S. The changes seen on the seismic were:

1) Minor drape in the upper coal
2) Small reduction in the coal event amplitude, suggesting thinning of coal
3) Lowering of the amplitude in the Tinowon section, suggesting the section is more homogenous i.e. possibly sandstone.

These anomalies were noted on seismic near the Booberanna dry hole, and are worth pursuing as a possible stratigraphic play.

GLJ believes that there are sufficient Tinowon penetrations for some diagnostic work to be carried out in attempting to identify Tinowon sandstones. Consideration should be given to reprocessing seismic data that ties wells that have Tinowon penetrations. If this work is carried out, attribute analysis should be undertaken on the reprocessed data in order to determine which, if any, parameters point to the presence of Tinowon sandstones. It may transpire that not all attributes are universally applicable; that is some attributes indicating sandstone may have limited areal application. However, by undertaking such a body of work, it may be possible to construct a Tinowon sandstone distribution map.

# GEOLOGY

## Play Description

With the exception of the Weribone stratigraphic prospect all identified prospects and leads are defined by structural closure. These prospect and leads were defined from work done by previous operators in the area and compiled on a regional map (Map 1). AusAm has done some preliminary mapping over these anomalies. GLJ has verified this mapping. Origin, using a set of reprocessed seismic data, has done more detailed mapping of the Ungabilla prospect and the Weribone prospect. Mapping and seismic sections show that the targeted structures are small low relief anticlines with four-way dip closure.

The identified prospects and leads are targeting liquids rich natural gas in the Late Permian age Tinowon Formation. The Tinowon, in particular the Upper Tinowon has become the primary exploration target on the western flank of the Taroom Trough. This is the main gas-producing interval in the offsetting Waggamba, Myall Creek and Churchie Fields (Map 1). Production from these fields has shown that these sands can be produced at reservoir depths of greater than 2000 meters. Recent wells in the Churchie and Myall Creek Fields demonstrate that drilling the reservoir section underbalanced has resulted in a substantial improvement in the test and production rates from the Permian reservoirs. Sample studies indicate that because of the presence of clays, the Permian Tinowon reservoir sands are susceptible to formation damage when drilled with traditional mud systems. It was previously believed that the Tinowon sands lacked sufficient porosity and permeability to be productive at these depths. Further, while the original wells drilled in these fields were drilled on structural closures, recent wells drilled in these fields have been drilled outside closure. While there are uncertainties with respect to lateral continuity in these reservoirs, this recent drilling indicates that the gas in these fields is trapped in larger stratigraphic traps. However, the potential for and possible extent of statigraphic trapping in the Tinowon sandstones cannot be properly evaluated based on the preliminary work done to date in the AusAm interest blocks.

In the area, the Upper Tinowon is defined as the sandstone unit immediately above the Wallabella coal member. The intra Wallabella sands were deposited within the Wallabella coals and the Lower Tinowon sand occurs below the coals. The Upper Tinowon sandstones are described as medium to coarse-grained sandstones, that were deposited in a complex fluvial-deltaic system. The Lower Tinowon section consists interbedded fine to coarse-grained sandstones shales and coals. These fluvial-deltaic systems generally trend west to east. Potential for development of Tinowon reservoir sands has been identified basinward of the western

basement highs (Wunger Ridge, Roma Shelf). GLJ has considered both the upper and Lower Tinowon intervals for risk and volumetric resource estimates.

**Exploration Risk Analysis**

***Methodology***

In the evaluation of exploration risk there are eight factors which must be addressed: the amount and type of kerogen in a source rock, the thermobaric history of the kerogen, the existence of migration pathway, the presence and age of the trap, the presence of reservoir, the existence of a seal, the timing of hydrocarbon expulsion and the preservation of the reservoir from post trapping destruction.

In assessing the exploration risk associated with the identified Tinowon prospects and leads GLJ has assigned a probability to each of these geological parameters for both of the potential reservoir horizons. The risks reflect the success seen in these zones to date. The product of all of these parameters provides the exploration risk; that is, the chance of finding any hydrocarbons in each of the potential reservoir horizons. The combined probability of success, that is the chance that at least one of the two potential reservoir horizons will be successful, having no consideration for an economic cutoff, is equal to one minus the chance that both the upper and lower Tinowon zones will fail. Prospects have a chance of success that is generally between 25 percent and 10 percent. Leads have higher risk. Volumetric analysis is conducted to determine the probability of discovering the minimum commercial size, and then this risk is included in order to arrive at a final estimate of the chance of success for each of the prospects. For this analysis an exploration prospect was considered noncommercial if no reservoir was encountered, or the recoverable resources did not exceed a minimum size. Note that in stacked sequences, the exploration risk and the commercial risk are best estimated by creating a single probability distribution on the risked resource size.

***Exploration Risk - Tinowon Play - General***

Based on a review of the results (well logs, test, well completion reports) from well drills through the Tinowon section to date, GLJ believes that the main geological risk associated with all the identified prospects and leads is reservoir, with respect to both the presence and quality of the sand.

Structural closure is the second critical risk associated with the defined prospects. Identified structures are small, low relief structures. These structures are defined on older data that has not been reprocessed. Origin has shown that reprocessing can change the seismic and therefore there are uncertainties with respect to structure.

GLJ believes there is little geological risk associated with hydrocarbon charge, timing or preservation. The Permian source rocks are very thick in the Taroom Trough area and have the potential to generate and expel large quantities of hydrocarbon. The number of hydrocarbon accumulations encountered indicates extensive lateral migration of the Permian sourced hydrocarbons out of the Taroom Trough to the western flank of the basin. The main phase of expulsion of hydrocarbons from these source rocks is interpreted to have occurred in the Early Cretaceous and it is likely that traps were in place before significant hydrocarbons were expelled. Shales within the Permian sequence provide top and bottom seals for the reservoirs. Any concerns with respect to seal are related to the trapping mechanism for the Weribone stratigraphic play, lateral faulting which extends into the Triassic section and the top seal for the Lower Tinowon sandstones. Exploration risks assigned for each of the reviewed prospects and leads are summarized on Tables 2 through 8. A brief discussion of each of the reviewed prospects and leads is presented below.

**ATP 470P**

***Weribone Lead***

The Weribone lead is a stratigraphic trap targeting the Upper Tinowon sandstone. The lead is located on the east side of the main Parknook/Weribone structure. It is interpreted that the Upper Tinowon sands will be present onlapping a seismically defined structural nose at the top the Tinowon level (Map 2). The mapped play area covers an area of approximately 975 acres. Gross rock volumes determined in Upper Tinowon resource estimates used this mapped area.

GLJ interprets the main exploration risk associated with this prospect is the presence of reservoir. The chance of the Upper Tinowon reservoir being present is estimated at 25 percent. The existence of a sand prone Tinowon section being present is speculative. The Tinowon section is not present in wells on the east side of the Parknook/Weribone structure. The Tinowon is developed in the Rednook and Redcap wells on the northwest flank of the structure. A seismic correlation can be made between these wells and the defined play area. It is noted that no reservoir sands are developed in the Redcap or Rednook wells. The other main risk associated

with this prospect is seal, as the stratigraphic trapping mechanism is poorly understood, but recent drilling in offset fields suggests that lateral sealing is possible.

**ATP 754P**

The majority of the AusAm identified prospects and leads occur on this block. With the exception of the Ungabilla prospect, all the prospects and leads have been identified using unreprocessed seismic data. The area and gross rock volumes for the potential reservoir horizons were determined using seismic time structure mapping at the Bandanna coal level. The Ungabilla prospect has been mapped using reprocessed data and depth structure mapping on the Tinowon level has been done.

***Ungabilla Lead***

The Ungabilla lead is located approximately 15 kilometers from the recently drilled Palmerston-1 well and is between the Waggamba (southwest) and Myall Creek (northwest) producing fields. This prospect would target Tinowon sandstones at an approximate depth of 2750 meters. Seismic reinterpretation of this lead has reduced the size of this structure to approximately 305 acres at the Upper Tinowon level. The structure has a vertical closure of approximately 85 feet. The structure is a three-way closure against a northeast-bounding fault (Map 3). The structure is on a trend interpreted to have Upper Tinowon section present. Reservoir quality appears to be the main risk associated with this prospect. Structural closure is the other critical risk. This prospect is small and uneconomic using a 2 BCF economic threshold.

***Flinton Lead***

The Flinton lead is located approximately 35 kilometers southeast of the Waggamba Field. The Flinton structure is a four-way dip closure that covers an approximate area of 1500 acres and has a vertical closure of 115 feet. The Flinton structure has been penetrated by a wellbore. The Flinton -1 well was drilled near the crest of the mapped structure and was drilled to basement. The Tinowon section occurs at a depth of 2650 meters in this well. The zone was not tested and AusAm believes that there was a gas show in the Permian section that has not been tested. Available logs over the section are poor, however in the well completion report it is concluded that no significant gas shows were encountered in the well and that no permeable zones were encountered in the Permian section. The uncertainty with respect to the presence of reservoir quality sands in the Tinowon in this well has been reflected in the exploration risk assigned to the presence of reservoir.

***Flinton South Lead***

The Flinton South structure is located approximately 5 kilometers southeast of the Flinton-1 well. The Flinton south structure is a small four-way closure, covering an area of approximately 715 acres with a vertical closure of 75 feet. The structure is small with very low chance of encountering a structurally trapped reservoir of commercial size.

***Farawell Prospect***

The Farawell prospect is located approximately 30 kilometers southeast of the Waggamba Field. The Farawell prospect is an 1800 acre structural closure as mapped at top Permian. It is estimated that the targeted Tinowon section would occur at an approximate depth of 2475 meters at this location. The vertical closure of the structure is approximately 75 feet. It is noted that the western closure of this anomaly is poorly defined. A review of wells in the southwest part of the block suggests that the Tinowon section is thinning and that in the offset Bellbird-1 and Bellbird South-1 wells the lower sand is not developed.

***Aurifer Downs Lead***

The Aurifer Downs structure is located approximately 60 kilometers south of the Waggamba Field. Mapping and seismic sections indicate that the structure is a low relief anticline with four-way closure at top Permian. The vertical closure of the structure is approximately 50 feet with an enclosing area of approximately 1900 acres. The structure has been penetrated by a well. The Aurifer Downs-1 well was drilled to the basement and AusAm has interpreted that there is bypassed pay in the Permian section of the well. Well logs do indicate the presence of sand in the Permian between the depths of 2127 meters and 2167 meters. These sands were suspected of being gas-bearing so a neutron density porosity log was run and sidewall cores were cut over the zone. Using this data the operator of the well concluded that the well had encountered no significant hydrocarbons and that gas peaks in the Permian section were due to coals. The uncertainty with respect to the presence of reservoir quality sands in the Permian in this well has been reflected in the exploration risk assigned to the presence of reservoir.

***Cockatoo Lead***

Mapping and seismic sections indicate that the Cockatoo anomaly is a low relief structure defined by four-way closure at top Permian. The vertical closure of the structure is approximately 60 feet with an enclosing area of approximately 1042 acres. It is noted that based on both AusAm and GLJ mapping the location of this structure has shifted. The anomaly is now mapped northeast of the Cockatoo-1 and Alton East-1 wells; while on the original prospect map these wells were within the structure. The Tinowon section in the Cockatoo-1 well occurs at a depth of 2180 meters and AusAm has interpreted that there is bypassed pay in this section. The uppermost sand in the Tinowon was drill stem tested and found to be tight. A second sandstone interval appears to have slightly better porosity development on logs but was not tested. The uncertainties noted with respect to reservoir quality and trap is reflected in the geological risk assigned to this lead. The chance of finding a commercial reservoir in this structural trap is very low.

The Cockatoo North and Farawell North leads were also reviewed by GLJ. These leads are interpreted to be small and uneconomic, and therefore were not reviewed further by GLJ.

# RESOURCES

## Volumetric Resource Estimates

Resource estimates for the prospects and leads defined on ATP470 and ATP754 have been made using the mapped rock volumes and reservoir parameters determined from a review of available well log data, core data and data contained in a number of technical reports. All parameters required for the volumetric resource estimate carry a high degree of uncertainty; therefore a probabilistic approach was adopted to provide a range in original-gas-in-place (OGIP) and recoverable gas. The procedure is summarized below:

1. The relationship between the vertical closure of the structure, and hence the gas column, to both the area and the gross rock volume of the reservoir sequence, at any thickness of the given sequence was determined. The range in gross thickness used for each of the potential reservoir sequences reflects the variation seen in wells in and offsetting the prospective structures.

2. The preliminary two-way-time structure maps for each of the prospective structures was used to define a probability distribution for the gas column. (The depth structure map for the Ungabilla structure was used). The hydrocarbon fill fraction of the Upper Tinowon is expected to be high because of the significant charge from the Permian section. This is supported by drilling in offset pools that have reportedly not encountered a water leg. The minimum value used for the Upper Tinowon corresponds to a hydrocarbon fill of approximately 70 percent. The most likely value used corresponds to a hydrocarbon fill of approximately 85 percent, whereas the maximum is the interval between the top of the structure and the spill point. A larger range in hydrocarbon fill fraction has been used for the Lower Tinowon section because water has been tested from this zone. The minimum value used for the Lower Tinowon corresponds to a hydrocarbon fill of approximately 60 percent. The most likely value used corresponds to a hydrocarbon fill of approximately 80 percent, whereas the maximum is the interval between the top of the structure and the spill point.

3. Interpretations were made on the likelihood that each sequence would cover the entire structure, or that lateral sandstone discontinuities and/or compartmentalization could restrict the accessible gas-in-place. This was included as a reduction factor on the gross rock volume.

4. The range in reservoir parameters used was determined after a review of well logs from a number of wells offsetting and drilled into the prospective structures. Data included in a

number of reports was also considered. Most of these parameters show significant variations across the area reviewed and this has been reflected in the ranges used.

5. A probability distribution for the recovery factor was also applied to define the recoverable gas resource volume.

A total of 5000 iterations were then run in order to define the probability distribution for the potential OGIP and the recoverable gas resource. The parameters that were input into the risk analysis model for the prospect and leads reviewed by GLJ are shown on Tables 2 to 8. From this analysis, mean unrisked OGIP of values were calculated for all the prospects and leads. The mean unrisked OGIP is calculated by dividing the sum of the chance weighted mean OGIP (risked) for the zones by the overall geological chance of success for that prospect. Mean unrisked recoverable resources were also calculated. Similarly, the mean unrisked recoverable resource is calculated by dividing the sum of the chance weighted mean resources (risked) for the zones by the overall geological chance of success for that prospect. The mean unrisked recoverable resource greater than the economic limit is calculated for each of the prospects by dividing the sum of the chance weighted mean resources (risked) greater than the economic limit for the zones by the overall chance of commercial success for that prospect. The mean unrisked OGIP, the mean unrisked recoverable resources and the mean unrisked recoverable resources greater the economic limit for each of the prospects and leads are summarized on Tables 2 to 8.

GLJ analyzed the potential value of these exploration plays by relating the exploration risk to the potential reward of a discovery. Calculating the expected monetary value of the play is one method that is in common use today.

The expected monetary value was calculated by comparing the risked net present value of a discovery to the risked cost of drilling an abandoned well:

$$EMV = CR \times NPV - (1-CR) \times Aban$$

Where: EMV = Expected Monetary Value
CR = Commercial Risk (Exploration Risk × Commercial Risk)
NPV = Net Present value of the potential discovery
Aban = Abandoned well cost.

In this case, GLJ considers the mean resource estimate in determining the NPV.

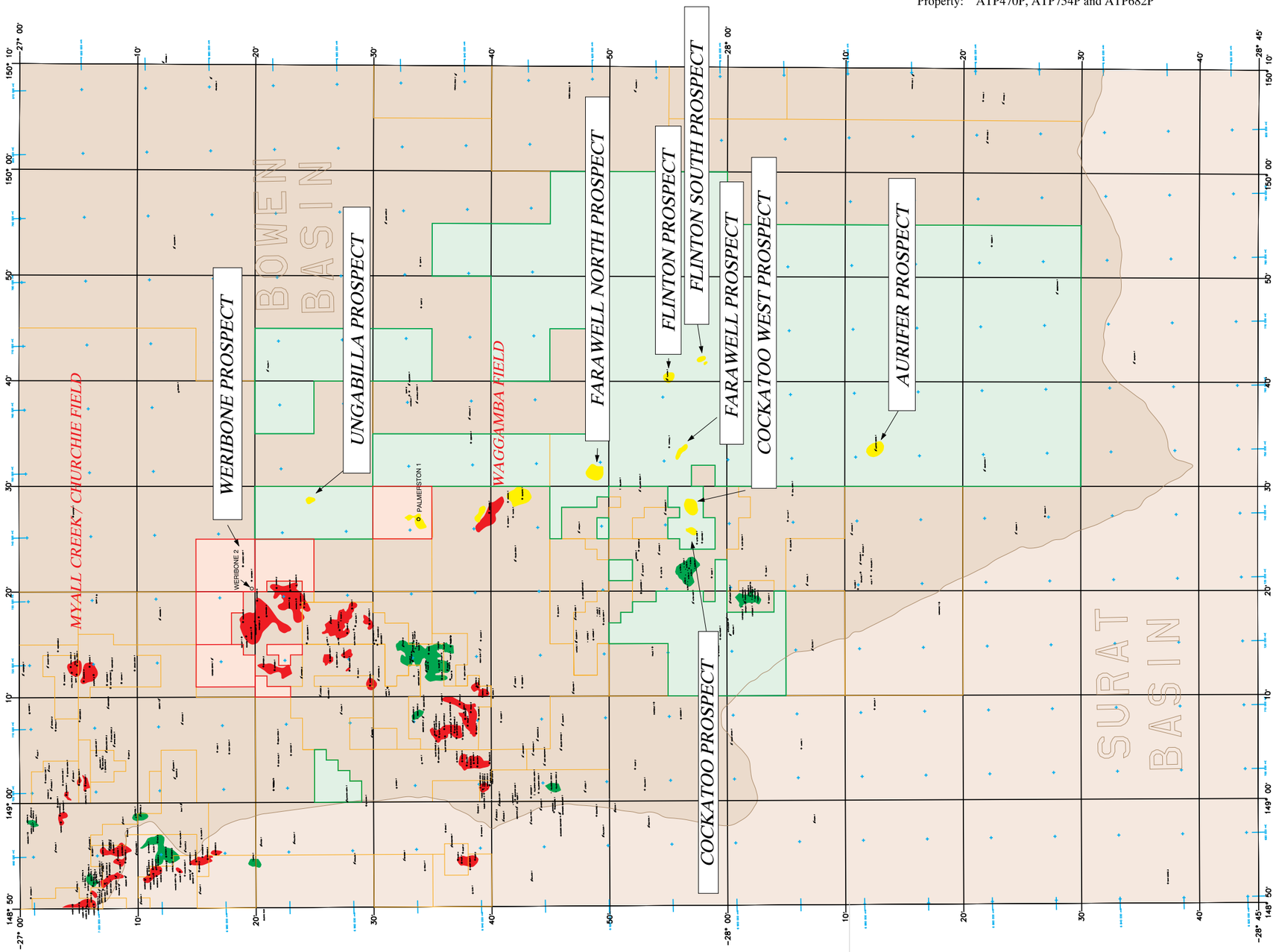
The calculated EMV's for all the prospects and leads reviewed by GLJ were negative. The negative EMV values result from the relatively small size of the identified structural prospects and high risk associated with them.

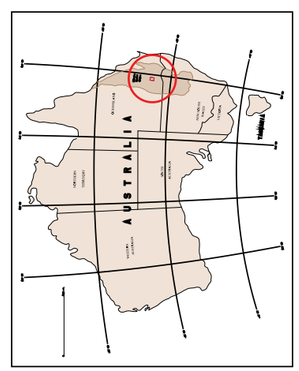
Map 1

# Land Map
## Land Blocks, Fields and Wells
## Queensland, Australia

Company: AusAm Resources Limited
Property: ATP470P, ATP754P and ATP682P

Effective Date: March 31, 2004
Scale: 1:650,000 s1046451/aarm01

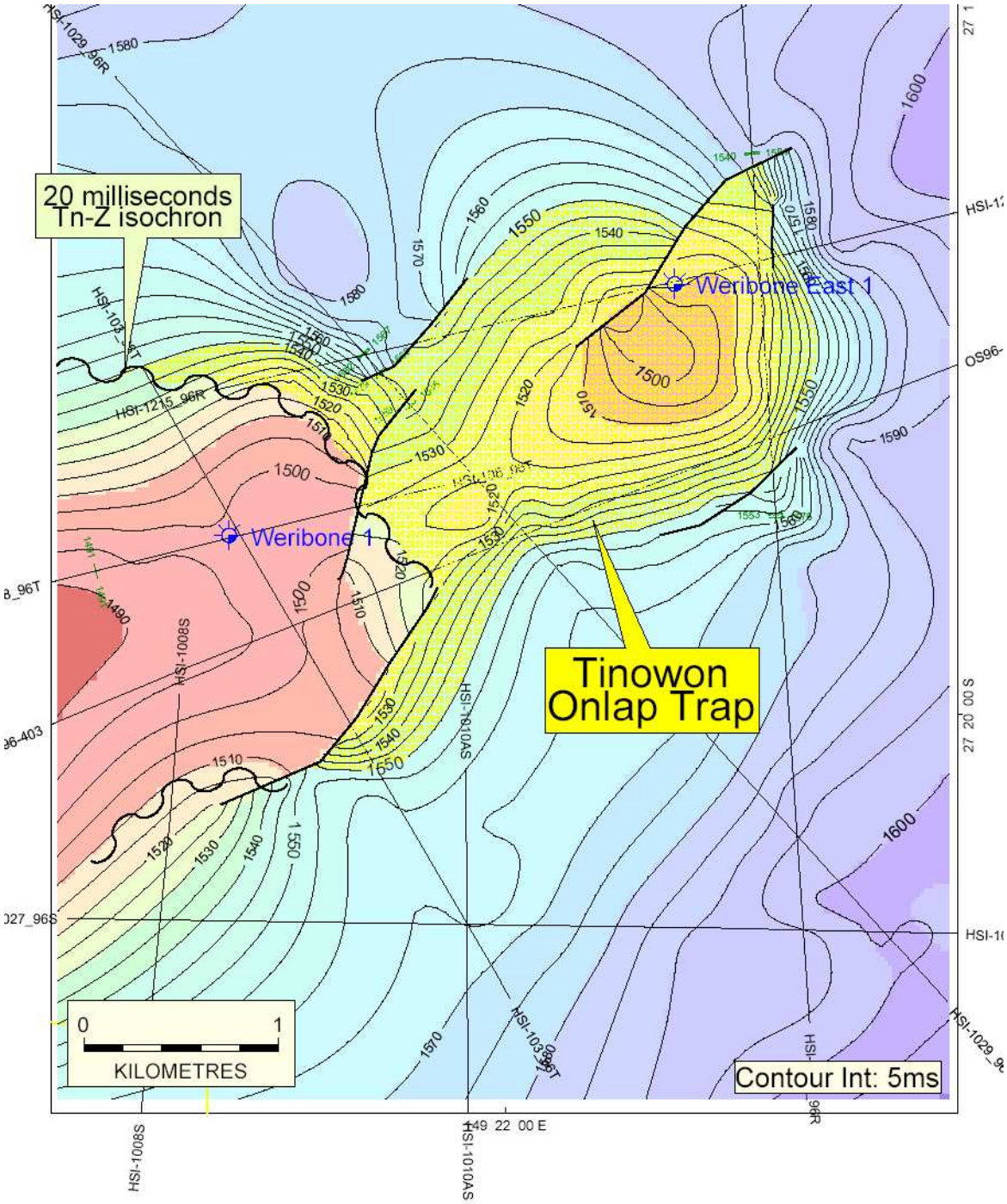


**Map 2**
**Top Tinowon Time Structure Map**
**Upper Tinowon Prospect**

Company: Ausam Resources Limited
Property: Weribone

Effective Date: March 31, 2004
Scale: NTS s1046451/aabm02



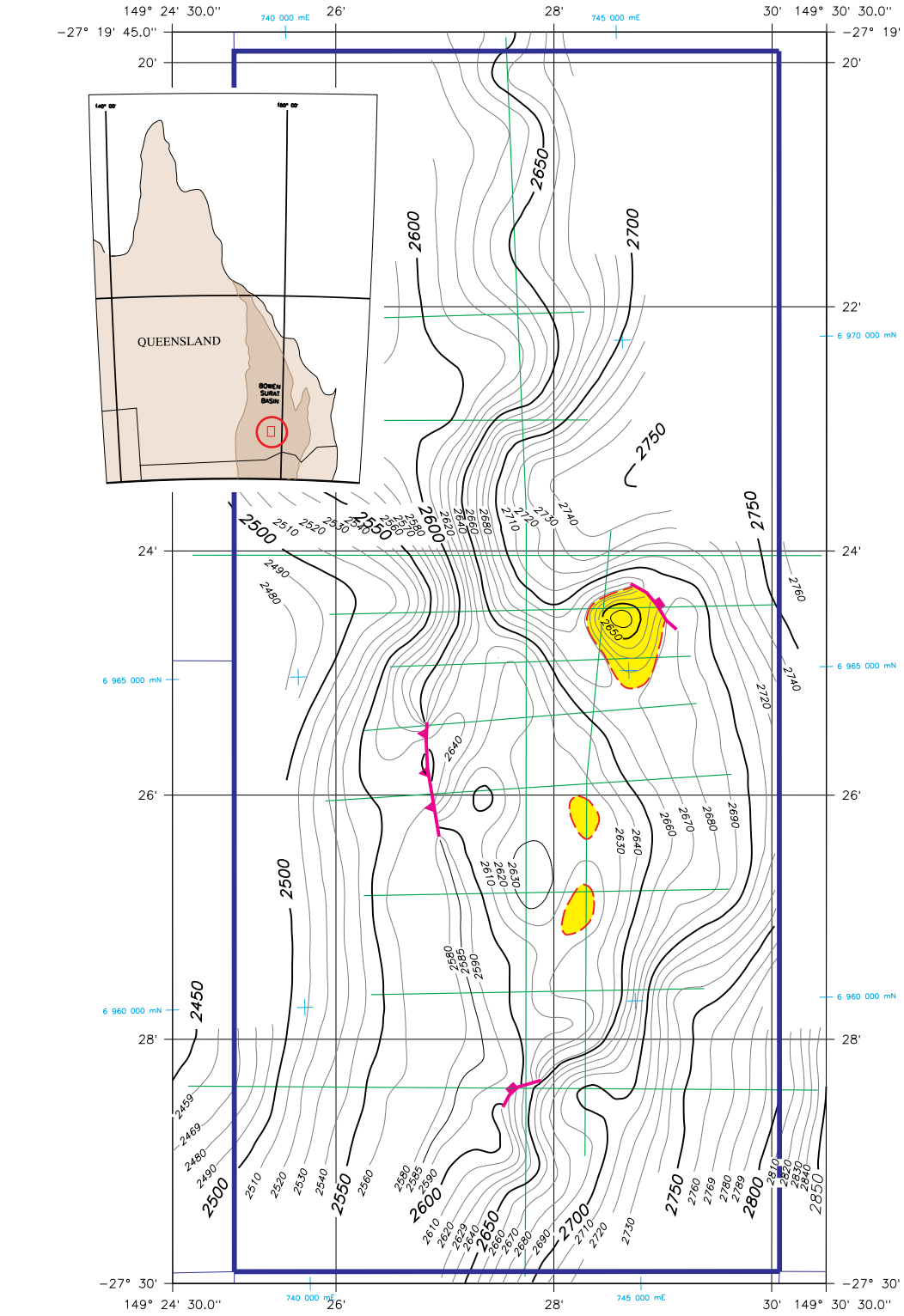

Source: Origin Energy Resources Limited

Map 3

# Depth Structure Map
# Near Top Wallabella Coal

Company: Ausum Resources Limited
Property: Ungabilla Prospect

Effective Date: March 31, 2004
Scale: 1:100,000 s1046451/aabm03



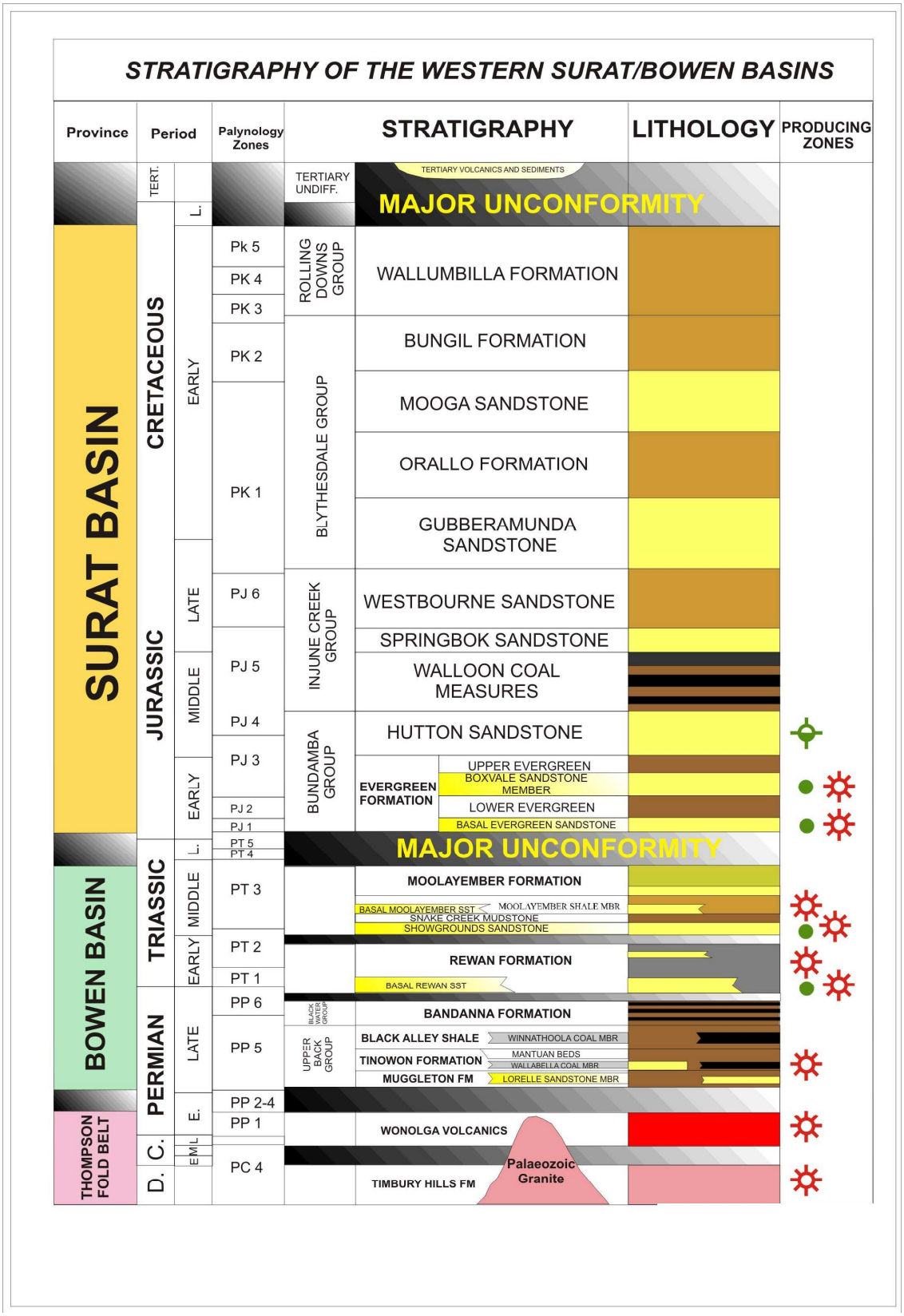

LEGEND:

UNGABILLA PROSPECT

SIESMIC REPROCESSED 2003

CONTOUR INTERVAL = 10 metres

# TABLE 1


STRATIGRAPHY OF THE WESTERN SURAT/BOWEN BASINS
Province
Period
Palynology Zones
STRATIGRAPHY
LITHOLOGY
PRODUCING ZONES
SURAT BASIN
BOWEN BASIN
THOMPSON FOLD BELT
TERT.
CRETACEOUS
JURASSIC
TRIASSIC
PERMIAN
L.
EARLY
MIDDLE
LATE
E.
EM
L.
C.
D.
TERTIARY UNDIFF.
TERTIARY VOLCANICS AND SEDIMENTS
MAJOR UNCONFORMITY
Pk 5
PK 4
PK 3
PK 2
PK 1
PJ 6
PJ 5
PJ 4
PJ 3
PJ 2
PJ 1
PT 5
PT 4
PT 3
PT 2
PT 1
PP 6
PP 5
PP 2-4
PP 1
PC 4
ROLLING DOWNS GROUP
WALLUMBILLA FORMATION
BLYTHESDALE GROUP
BUNGIL FORMATION
MOOGA SANDSTONE
ORALLO FORMATION
GUBBERAMUNDA SANDSTONE
INJUNE CREEK GROUP
WESTBOURNE SANDSTONE
SPRINGBOK SANDSTONE
WALLOON COAL MEASURES
BUNDAMBA GROUP
HUTTON SANDSTONE
EVERGREEN FORMATION
UPPER EVERGREEN
BOXVALE SANDSTONE MEMBER
LOWER EVERGREEN
BASAL EVERGREEN SANDSTONE
MAJOR UNCONFORMITY
MOOLAYEMBER FORMATION
BASAL MOOLAYEMBER SST
MOOLAYEMBER SHALE MBR
SNAKE CREEK MUDSTONE
SHOWGROUNDS SANDSTONE
REWAN FORMATION
BASAL REWAN SST
BLACK WATER GROUP
BANDANNA FORMATION
UPPER BACK GROUP
BLACK ALLEY SHALE
WINNATHOOLA COAL MBR
TINOWON FORMATION
MANTUAN BEDS
WALLABELLA COAL MBR
MUGGLETON FM
LORELLE SANDSTONE MBR
WONOLGA VOLCANICS
TIMBURY HILLS FM
Palaeozoic Granite

## Table 2 Weribone Lead
## Probabilistic Estimate of Recoverable Gas Resources and Exploration Risk Analysis

| | | | |
|---|---|---|---|
| Field | Flinton | | |
| Zone | Upper Tinowon | | |
| Entity | 1 | | |
| **Unrisked Resource Assessment** | | | |
| Reservoir and Fluid Properties | Mean Value | Distribution | Variability/Comments * |
| Gas Column Height (ft) | | Tlognorm | |
| Gross sequence thickness (ft) | 48.3 | Triangular | 5, 43, 98 |
| Area (acres) | 978.0 | Calculated | Interpolated from volumetric table |
| Initial Gross Rock Volume (acreft) | 47270 | Calculated | Interpolated from volumetric table |
| Reservoir coverage (%) | 0.800 | Triangular | 0.8,0.9,1 |
| Net / Gross Ratio | 0.31 | Triangular | 0.15,0.3,0.45 |
| Porosity (%) | 0.126 | Triangular | 0.11,0.12,0.14 |
| Water Saturation | 0.50 | Uniform | 0.4,0.6 |
| Initial Pressure (psia) | 3925 | Calculated | Used estimated pressure gradient |
| Temperature (F) | 175 | Calculated | Used estimated temp gradient |
| Gas Deviation (z) | 0.896 | Calculated | 1.5, 0.2, 1.25,1.75 |
| Formation Volume Factor | 244.2 | Calculated | |
| OGIP (bcf) | 7.8 | Calc | |
| Recovery Factor (%) | 0.65 | Triangular | 0.5,0.6,0.7 |
| Surf loss + Plant Fuel | 0.06 | Triangular | 0.05,0.06,0.07 |
| Unrisked Resources (bcf ) | 4.8 | Calc | |
| **Exploration Risk** | | | |
| Source | 100.0% | offset production, Permian source | |
| Maturity | 100.0% | offset production, Permian source | |
| Migration | 85.0% | Located on mapped migration pathway from Tinowon Trough | |
| Reservoir Rock | 25.0% | exisistence of sand prone Tinowon section speclative see comments | |
| Seal | 60.0% | strat trap mechanism poorly understood, lateral sealing possible.Faulting | |
| Trap | 85.0% | structural nose well defined on reprocessed seismic data | |
| Timing | 100.0% | | |
| Preservation | 100.0% | | |
| Final Exploration Risk | 10.8% | | |

Notes

Values shown in the "Mean Value" column are average values of the corresponding probability distribution function.
The values in this table will defer from the final estimate of unrisked resource size due to) the application of
a commercial limit to the distribution before calculating the unrisked size in the final table
* For truncated lognormal and truncated normal, the four values represent the input mean, standard deviation, minimum, and maximum
* For triangular, the three values represent the input minimum, mean, and maximum

**Mean Unrisked Resources>econ limit= 4.96 bcf**
**Pc (economic discovery)= 10.1%**

## Table 3: Ungabilla Lead
## Probabilistic Estimate of Recoverable Gas Resources and Exploration Risk Analysis

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Field | Ungabilla | | | Ungabilla | | |
| Zone | Upper Tinowon | | | Lower Tinowon | | |
| Entity | 1 | | | 2 | | |
| **Unrisked Resource Assessment** | | | | | | | |
| Reservoir and Fluid Properties | Mean Value | Distribution | Variability/Comments * | Mean Value | Distribution | Variability/Comments * |
| Gas Column Height (ft) | 75 | Tlognorm | 75,8.8,65,86 | 65 | Tlognorm | 230, 100, 50, 310 |
| Gross sequence thickness (ft) | 48.3 | Triangular | 15,45,85 | 40.0 | Triangular | 175, 225, 275 |
| Area (acres) | 246.9 | Calculated | Interpolated from volumetric table | 205.8 | Calculated | Interpolated from volumetric table |
| Initial Gross Rock Volume (acreft) | 7288 | Calculated | Interpolated from volumetric table | 5141 | Calculated | Interpolated from volumetric table |
| Reservoir coverage (%) | 0.900 | Triangular | 0.8,0.9,1 | 0.900 | Triangular | 0.8,0.9,1 |
| Net / Gross Ratio | 0.32 | Triangular | 0.2,0.32,0.45 | 0.32 | Triangular | 0.3, 0.1, 0.2, 0.45 |
| Porosity (%) | 0.128 | Triangular | 0.11,0.128,0.145 | 0.125 | Triangular | 0.11, 0.126, 0.14 |
| Water Saturation | 0.50 | Uniform | 0.4,0.6 | 0.50 | Uniform | 0.4,0.6 |
| Initial Pressure (psia) | 5336 | Calculated | Used estimated pressure gradient | 5336 | Calculated | Used estimated pressure gradient |
| Temperature (F) | 185 | Calculated | Used estimated temp gradient | 185 | Calculated | Used estimated temp gradient |
| Gas Deviation (z) | 1.016 | Calculated | | 1.016 | Calculated | |
| Formation Volume Factor | 288.2 | Calculated | | 288.2 | Calculated | |
| OGIP (bcf) | 1.7 | Calc | | 1.2 | Calc | |
| Recovery Factor (%) | 0.60 | Triangular | 0.5,0.6,0.7 | 0.60 | Triangular | 0.5,0.6,0.7 |
| Surf loss + Plant Fuel | 0.06 | Triangular | 0.05,0.06,0.07 | 0.06 | Triangular | 0.05,0.06,0.07 |
| Unrisked Resources (bcf ) | 0.96 | Calc | | 0.7 | Calc | |
| **Exploration Risk** | | | | | | |
| Source | 100.0% | offset production, Permian source | | 100.0% | offset production, Permian source | |
| Maturity | 100.0% | offset production, Permian source | | 100.0% | offset production, Permian source | |
| Migration | 85.0% | west flank off trough, offset production, shows to NW | | 85.0% | west flank off trough, offset production, shows to NW | |
| Reservoir Rock | 45.0% | on a trend interpreted to have upper Tinowon section, Pdev at Palmerston | | 40.0% | generally poorer quality, logs and tests | |
| Seal | 80.0% | shale and intraformational silts and shales, northeast bounding fault? | | 65.0% | top seal Wallabella coal? northeast bounding fault? | |
| Trap | 60.0% | small strucure defined, Reprocessing reduced size | | 100.0% | small strucure defined, Reprocessing reduced size | |
| Timing | 100.0% | | | 60.0% | | |
| Preservation | 100.0% | | | 100.0% | | |
| Final Exploration Risk | 18.4% | | | 13.3% | | |

Notes

Values shown in the "Mean Value" column are average values of the corresponding probability distribution function.

The values in this table will defer from the final estimate of unrisked resource size due to) the application of a commercial limit to the distribution before calculating the unrisked size in the final table

* For truncated lognormal and truncated normal, the four values represent the input mean, standard deviation, minimum, and maximum

**Mean Unrisked OGIP= 1.52**
**Mean Unrisked Resources= 0.86**
**COS(geological)= 29.3%**

**Mean Unrisked Resources>econ limit=** no outcomes greater than 2 bcf
**Pc (economic discovery)=**

## Table 4: Flinton Lead
## Probabilistic Estimate of Recoverable Gas Resources and Exploration Risk Analysis

| | | | | | | |
|---|---|---|---|---|---|---|
| Field | Flinton | | | Flinton | | |
| Zone | Upper Tinowon | | | Lower Tinowon | | |
| Entity | 1 | | | 2 | | |
| **Unrisked Resource Assessment** | | | | | | |
| Reservoir and Fluid Properties | Mean Value | Distribution | Variability/Comments * | Mean Value | Distribution | Variability/Comments * |
| Gas Column Height (ft) | 97 | Tlognorm | 98, 10.8, 80, 115 | 91 | Tlognorm | 92, 15.5, 70, 115) |
| Gross sequence thickness (ft) | 52.0 | Triangular | 15, 43, 98 | 45.0 | Triangular | 10, 35, 90 |
| Area (acres) | 1177.5 | Calculated | Interpolated from volumetric table | 1065.0 | Calculated | Interpolated from volumetric table |
| Initial Gross Rock Volume (acreft) | 41082 | Calculated | Interpolated from volumetric table | 33034 | Calculated | Interpolated from volumetric table |
| Reservoir coverage (%) | 0.900 | Triangular | 0.8,0.9,1 | 0.900 | Triangular | 0.8,0.9,1 |
| Net / Gross Ratio | 0.30 | Triangular | 0.15,0.3,0.45 | 0.30 | Triangular | 0.15,0.3,0.45 |
| Porosity (%) | 0.123 | Triangular | 0.11,0.12,0.14 | 0.118 | Triangular | 0.105, 0.115, 0.135 |
| Water Saturation | 0.50 | Uniform | 0.4,0.6 | 0.50 | Uniform | 0.4,0.6 |
| Initial Pressure (psia) | 4805 | Calculated | Used estimated pressure gradient | 4805.0 | Calculated | Used estimated pressure gradient |
| Temperature (F) | 185 | Calculated | Used estimated temp gradient | 185 | Calculated | Used estimated temp gradient |
| Gas Deviation (z) | 0.968 | Calculated | | 0.968 | Calculated | |
| Formation Volume Factor | 272.4 | Calculated | | 272.4 | Calculated | |
| OGIP (bcf) | 8.1 | Calc | | 6.3 | Calc | |
| Recovery Factor (%) | 0.60 | Triangular | 0.5,0.6,0.7 | 0.60 | Triangular | 0.5,0.6,0.7 |
| Surf loss + Plant Fuel | 0.06 | Triangular | 0.05,0.06,0.07 | 0.06 | Triangular | 0.05,0.06,0.07 |
| Unrisked Resources (bcf ) | 4.6 | Calc | | 3.5 | Calc | |
| **Exploration Risk** | | | | | | |
| Source | 100.0% | offset production, Permian source | | 100.0% | offset production, Permian source | |
| Maturity | 100.0% | offset production, Permian source | | 100.0% | offset production, Permian source | |
| Migration | 80.0% | west flank off trough, offset production, shows to NW | | 80.0% | west flank off trough, offset production, shows to NW | |
| Reservoir Rock | 20.0% | Flinton 1 aband., with no significant gas shows, no K zones noted in Permian, Bypas | | 17.5% | generally poorer quality, logs and tests | |
| Seal | 95.0% | | | 90.0% | top seal Wallabella coal? | |
| Trap | 50.0% | small low relief strucure defined on old data | | 50.0% | small low relief strucure defined on old data | |
| Timing | 100.0% | | | 100.0% | | |
| Preservation | 100.0% | | | 100.0% | | |
| Final Exploration Risk | 7.6% | | | 6.3% | | |

Notes

Values shown in the "Mean Value" column are average values of the corresponding probability distribution function.

The values in this table will defer from the final estimate of unrisked resource size due to) the application of a commercial limit to the distribution before calculating the unrisked size in the final table

* For truncated lognormal and truncated normal, the four values represent the input mean, standard deviation, minimum, and maximum

* For triangular, the three values represent the input minimum, mean, and maximum

| | | |
|---|---|---|
| **Mean Unrisked OGIP=** | **7.35** | **bcf** |
| **Mean Unrisked Resources=** | **4.17** | **bcf** |
| **COS(geological)=** | **13.3%** | |
| **Mean Unrisked Resources>econ limit=** | **5.02** | **bcf** |
| **Pc (economic discovery)=** | **9.1%** | |

## Table 5: Flinton South Lead
## Probabilistic Estimate of Recoverable Gas Resources and Exploration Risk Analysis

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Field | Flinton South | | | Flinton South | | | |
| Zone | Upper Tinowon | | | Lower Tinowon | | | |
| Entity | 1 | | | 2 | | | |
| **Unrisked Resource Assessment** | | | | | | | |
| Reservoir and Fluid Properties | Mean Value | Distribution | Variability/Comments * | Mean Value | Distribution | Variability/Comments * | |
| Gas Column Height (ft) | 63 | Tlognorm | 64, 8.4, 52, 75 | 59 | Tlognorm | 60, 8.9, 45, 75 | |
| Gross sequence thickness (ft) | 42.7 | Triangular | 10,43,75 | 43.3 | Triangular | 10, 45, 75 | |
| Area (acres) | 583.0 | Calculated | Interpolated from volumetric table | 539.9 | Calculated | Interpolated from volumetric table | |
| Initial Gross Rock Volume (acreft) | 15062 | Calculated | Interpolated from volumetric table | 13577 | Calculated | Interpolated from volumetric table | |
| Reservoir coverage (%) | 0.900 | Triangular | 0.8,0.9,1 | 0.900 | Triangular | 0.8,0.9,1 | |
| Net / Gross Ratio | 0.30 | Triangular | 0.1, 0.3, 0.5 | 0.28 | Triangular | 0.1, 0.3, 0.45 | |
| Porosity (%) | 0.125 | Triangular | 0.11,0.12,0.145 | 0.122 | Triangular | 0.105, 0.115, 0.135 | |
| Water Saturation | 0.50 | Uniform | 0.4,0.6 | 0.50 | Uniform | 0.4,0.6 | |
| Initial Pressure (psia) | 4950 | Calculated | Used estimated pressure gradient | 4950.0 | Calculated | Used estimated pressure gradient | |
| Temperature (F) | 188 | Calculated | Used estimated temp gradient | 188 | Calculated | Used estimated temp gradient | |
| Gas Deviation (z) | 0.981 | Calculated | | 0.981 | Calculated | | |
| Formation Volume Factor | 275.7 | Calculated | | 275.7 | Calculated | | |
| OGIP (bcf) | 3.1 | Calc | | 2.5 | Calc | | |
| Recovery Factor (%) | 0.60 | Triangular | 0.5,0.6,0.7 | 0.60 | Triangular | 0.5,0.6,0.7 | |
| Surf loss + Plant Fuel | 0.06 | Triangular | 0.05,0.06,0.07 | 0.06 | Triangular | 0.05,0.06,0.07 | |
| Unrisked Resources (bcf ) | 1.7 | Calc | | 1.4 | Calc | | |
| **Exploration Risk** | | | | | | | |
| Source | 100.0% | offset production, Permian source | | 100.0% | offset production, Permian source | | |
| Maturity | 100.0% | offset production, Permian source | | 100.0% | offset production, Permian source | | |
| Migration | 80.0% | west flank off trough, offset production, shows to NW | | 80.0% | west flank off trough, offset production, shows to NW | | |
| Reservoir Rock | 25.0% | south of drilled Flinton structure | | 20.0% | generally poorer quality, logs and tests | | |
| Seal | 95.0% | | | 90.0% | top seal Wallabella coal? | | |
| Trap | 50.0% | small low relief strucure defined on old data | | 50.0% | small low relief strucure defined on old data | | |
| Timing | 100.0% | | | 100.0% | | | |
| Preservation | 100.0% | | | 100.0% | | | |
| Final Exploration Risk | 9.5% | | | 7.2% | | | |

Notes

Values shown in the "Mean Value" column are average values of the corresponding probability distribution function.

The values in this table will defer from the final estimate of unrisked resource size due to) the application of a commercial limit to the distribution before calculating the unrisked size in the final table

* For truncated lognormal and truncated normal, the four values represent the input mean, standard deviation, minimum, and maximum

* For triangular, the three values represent the input minimum, mean, and maximum

**Mean Unrisked OGIP= 2.77 bcf**
**Mean Unrisked Resources= 1.57 bcf**
**COS(geological)= 16.1%**

**Mean Unrisked Resources>econ limit= 3.72 bcf**
**Pc (economic discovery)= 0.4%** ery low pobability of exceeding economic threshold

## Table 6: Farawell Prospect
## Probabilistic Estimate of Recoverable Gas Resources and Exploration Risk Analysis

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Field | Farawell | | | Farawell | | |
| Zone | Upper Tinowon | | | Lower Tinowon | | |
| Entity | 1 | | | 2 | | |
| **Unrisked Resource Assessment** | | | | | | | |
| Reservoir and Fluid Properties | Mean Value | Distribution | Variability/Comments * | Mean Value | Distribution | Variability/Comments * |
| Gas Column Height (ft) | 63 | Tlognorm | 64, 8.4, 52, 75 | 59 | Tlognorm | 60, 9.5, 45, 75 |
| Gross sequence thickness (ft) | 41.3 | Triangular | 10, 40, 74 | 38.0 | Triangular | 5, 35, 74 |
| Area (acres) | 1465.4 | Calculated | Interpolated from volumetric table | 1352.7 | Calculated | Interpolated from volumetric table |
| Initial Gross Rock Volume (acreft) | 37243 | Calculated | Interpolated from volumetric table | 31744 | Calculated | Interpolated from volumetric table |
| Reservoir coverage (%) | 0.900 | Triangular | 0.8,0.9,1 | 0.900 | Triangular | 0.8,0.9,1 |
| Net / Gross Ratio | 0.27 | Triangular | 0.1,0.3,0.4 | 0.25 | Triangular | 0.1,0.25,0.4 |
| Porosity (%) | 0.125 | Triangular | 0.11, 0.125, 0.14 | 0.121 | Triangular | 0.105, 0.124, 0.135 |
| Water Saturation | 0.50 | Uniform | 0.4,0.6 | 0.50 | Uniform | 0.4,0.6 |
| Initial Pressure (psia) | 4290 | Calculated | Used estimated pressure gradient | 4290.0 | Calculated | Used estimated pressure gradient |
| Temperature (F) | 185 | Calculated | Used estimated temp gradient | 185 | Calculated | Used estimated temp gradient |
| Gas Deviation (z) | 0.922 | Calculated | | 0.922 | Calculated | |
| Formation Volume Factor | 255.2 | Calculated | | 255.2 | Calculated | |
| OGIP (bcf) | 6.2 | Calc | | 4.8 | Calc | |
| Recovery Factor (%) | 0.60 | Triangular | 0.5,0.6,0.7 | 0.60 | Triangular | 0.5,0.6,0.7 |
| Surf loss + Plant Fuel | 0.06 | Triangular | 0.05,0.06,0.07 | 0.06 | Triangular | 0.05,0.06,0.07 |
| Unrisked Resources (bcf ) | 3.5 | Calc | | 2.7 | Calc | |
| **Exploration Risk** | | | | | | |
| Source | 100.0% | offset production, Permian source | | 100.0% | offset production, Permian source | |
| Maturity | 100.0% | offset production, Permian source | | 100.0% | offset production, Permian source | |
| Migration | 80.0% | west flank off trough, offset production, shows to NW | | 80.0% | west flank off trough, offset production, shows to NW | |
| Reservoir Rock | 35.0% | Sands thin in offsets in southern part of block, reservoir quality ? | | 30.0% | Lwr vs intra-Wallabella sand int Bellbird wells, poorer quality | |
| Seal | 95.0% | Black Alley shale and intraformational silts and shales (top and base), | | 90.0% | top seal Wallabella coal? | |
| Trap | 50.0% | small low relief strucure defined on old data, Closure to NW? | | 100.0% | small low relief strucure defined on old data, Closure to NW? | |
| Timing | 100.0% | | | 50.0% | | |
| Preservation | 100.0% | | | 100.0% | | |
| Final Exploration Risk | 13.3% | | | 10.8% | | |

Notes

Values shown in the "Mean Value" column are average values of the corresponding probability distribution function.

The values in this table will defer from the final estimate of unrisked resource size due to) the application of a commercial limit to the distribution before calculating the unrisked size in the final table

* For truncated lognormal and truncated normal, the four values represent the input mean, standard deviation, minimum, and maximum

* For triangular, the three values represent the input minimum, mean, and maximum

| | | |
|---|---|---|
| **Mean Unrisked OGIP=** | **5.73** | **bcf** |
| **Mean Unrisked Resources=** | **3.24** | **bcf** |
| **COS(geological)=** | **22.7%** | |
| **Mean Unrisked Resources>econ limit=** | **4.42** | **bcf** |
| **Pc (economic discovery)=** | **10.9%** | |

## Table 7: Aurifer Downs
## Probabilistic Estimate of Recoverable Gas Resources and Exploration Risk Analysis

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Field | Aurifer Downs | | | Aurifer Downs | | | |
| Zone | Upper Tinowon | | | Lower Tinowon | | | |
| Entity | 1 | | | 2 | | | |
| **Unrisked Resource Assessment** | | | | | | | |
| Reservoir and Fluid Properties | Mean Value | Distribution | Variability/Comments * | Mean Value | Distribution | Variability/Comments * | |
| Gas Column Height (ft) | 47 | Tlognorm | 47, 5, 39, 55 | 43 | Tlognorm | 44, 7.2, 33, 55 | |
| Gross sequence thickness (ft) | 35.0 | Triangular | 10, 40, 55 | 30.3 | Triangular | 5, 31, 55 | |
| Area (acres) | 1648.6 | Calculated | Interpolated from volumetric table | 1547.8 | Calculated | Interpolated from volumetric table | |
| Initial Gross Rock Volume (acreft) | 36867 | Calculated | Interpolated from volumetric table | 31559 | Calculated | Interpolated from volumetric table | |
| Reservoir coverage (%) | 0.900 | Triangular | 0.8,0.9,1 | 0.900 | Triangular | 0.8,0.9,1 | |
| Net / Gross Ratio | 0.30 | Triangular | 0.1, 0.3, 0.5 | 0.25 | Triangular | 0.1, 0.25, 0.4 | |
| Porosity (%) | 0.128 | Triangular | 0.11, 0.13, 0.145 | 0.121 | Triangular | 0.105, 0.124, 0.135 | |
| Water Saturation | 0.50 | Uniform | 0.4,0.6 | 0.50 | Uniform | 0.4,0.6 | |
| Initial Pressure (psia) | 3485 | Calculated | Used estimated pressure gradient | 3485.0 | Calculated | Used estimated pressure gradient | |
| Temperature (F) | 155 | Calculated | Used estimated temp gradient | 155 | Calculated | Used estimated temp gradient | |
| Gas Deviation (z) | 0.867 | Calculated | | 0.867 | Calculated | | |
| Formation Volume Factor | 231.3 | Calculated | | 231.3 | Calculated | | |
| OGIP (bcf) | 6.4 | Calc | | 4.3 | Calc | | |
| Recovery Factor (%) | 0.60 | Triangular | 0.5,0.6,0.7 | 0.60 | Triangular | 0.5,0.6,0.7 | |
| Surf loss + Plant Fuel | 0.06 | Triangular | 0.05,0.06,0.07 | 0.06 | Triangular | 0.05,0.06,0.07 | |
| Unrisked Resources (bcf ) | 3.6 | Calc | | 2.4 | Calc | | |
| **Exploration Risk** | | | | | | | |
| Source | 100.0% | offset production, Permian source | | 100.0% | offset production, Permian source | | |
| Maturity | 100.0% | offset production, Permian source | | 100.0% | offset production, Permian source | | |
| Migration | 80.0% | west flank off trough, offset production, shows to NW | | 80.0% | west flank off trough, offset production, shows to NW | | |
| Reservoir Rock | 22.5% | Aurifer 1 well bypassed pay? Operator conclude no gas sands | | 20.0% | Aurifer 1 well bypassed pay? Operator conclude no gas sands | | |
| Seal | 95.0% | | | 90.0% | top seal Wallabella coal? | | |
| Trap | 50.0% | small low relief strucure defined on old data | | 50.0% | small low relief strucure defined on old data | | |
| Timing | 100.0% | | | 100.0% | | | |
| Preservation | 100.0% | | | 100.0% | | | |
| Final Exploration Risk | 8.6% | | | 7.2% | | | |

Notes

Values shown in the "Mean Value" column are average values of the corresponding probability distribution function.

The values in this table will defer from the final estimate of unrisked resource size due to) the application of a commercial limit to the distribution before calculating the unrisked size in the final table

* For truncated lognormal and truncated normal, the four values represent the input mean, standard deviation, minimum, and maximum

* For triangular, the three values represent the input minimum, mean, and maximum

| | | |
|---|---|---|
| **Mean Unrisked OGIP=** | **5.54** | **bcf** |
| **Mean Unrisked Resources=** | **3.13** | **bcf** |
| **COS(geological)=** | **15.2%** | |
| **Mean Unrisked Resources>econ limit=** | **4.52** | **bcf** |
| **Pc (economic discovery)=** | **6.5%** | |

## Table 8: Cockatoo Lead
## Probabilistic Estimate of Recoverable Gas Resources and Exploration Risk Analysis

| Field | Cockatoo | | | Cockatoo | | |
|---|---|---|---|---|---|---|
| Zone | Upper Tinowon | | | Lower Tinowon | | |
| Entity | 1 | | | 2 | | |
| **Unrisked Resource Assessment** | | | | | | |
| Reservoir and Fluid Properties | Mean Value | Distribution | Variability/Comments * | Mean Value | Distribution | Variability/Comments * |
| Gas Column Height (ft) | 52 | Tlognorm | 53, 7.2, 43, 62.5 | 50 | Tlognorm | 50, 8, 38, 63 |
| Gross sequence thickness (ft) | 37.3 | Triangular | 5, 45, 62 | 34.0 | Triangular | 10, 32, 60 |
| Area (acres) | 788.8 | Calculated | Interpolated from volumetric table | 717.5 | Calculated | Interpolated from volumetric table |
| Initial Gross Rock Volume (acreft) | 15814 | Calculated | Interpolated from volumetric table | 13679 | Calculated | Interpolated from volumetric table |
| Reservoir coverage (%) | 0.900 | Triangular | 0.8,0.9,1 | 0.900 | Triangular | 0.8,0.9,1 |
| Net / Gross Ratio | 0.27 | Triangular | 0.1,0.3,0.4 | 0.27 | Triangular | 0.1, 0.25, 0.45 |
| Porosity (%) | 0.125 | Triangular | 0.11, 0.124, 0.14 | 0.120 | Triangular | 0.105, 0.12, 0.135 |
| Water Saturation | 0.50 | Uniform | 0.4,0.6 | 0.50 | Uniform | 0.4,0.6 |
| Initial Pressure (psia) | 3485 | Calculated | Used estimated pressure gradient | 3485.0 | Calculated | Used estimated pressure gradient |
| Temperature (F) | 155 | Calculated | Used estimated temp gradient | 155 | Calculated | Used estimated temp gradient |
| Gas Deviation (z) | 0.867 | Calculated | | 0.867 | Calculated | |
| Formation Volume Factor | 231.3 | Calculated | | 231.3 | Calculated | |
| OGIP (bcf) | 2.4 | Calc | | 2.0 | Calc | |
| Recovery Factor (%) | 0.60 | Triangular | 0.5,0.6,0.7 | 0.60 | Triangular | 0.5,0.6,0.7 |
| Surf loss + Plant Fuel | 0.06 | Triangular | 0.05,0.06,0.07 | 0.06 | Triangular | 0.05,0.06,0.07 |
| Unrisked Resources (bcf ) | 1.3 | Calc | | 1.1 | Calc | |
| **Exploration Risk** | | | | | | |
| Source | 100.0% | offset production, Permian source | | 100.0% | offset production, Permian source | |
| Maturity | 100.0% | offset production, Permian source | | 100.0% | offset production, Permian source | |
| Migration | 80.0% | west flank off trough, offset production, shows to NW | | 80.0% | west flank off trough, offset production, shows to NW | |
| Reservoir Rock | 30.0% | offset Cockatoo 1 well, 2 sands upr ti test lwr better phi, bypassed? | | 25.0% | offset Cockatoo 1 lwr sand tight | |
| Seal | 95.0% | | | 90.0% | | |
| Trap | 100.0% | small low relief strucure defined on old data, location shift ne | | 100.0% | small low relief strucure defined on old data location shift ne | |
| Timing | 50.0% | | | 50.0% | | |
| Preservation | 100.0% | | | 100.0% | | |
| Final Exploration Risk | 11.4% | | | 9.0% | | |

Notes

Values shown in the "Mean Value" column are average values of the corresponding probability distribution function.

The values in this table will defer from the final estimate of unrisked resource size due to) the application of a commercial limit to the distribution before calculating the unrisked size in the final table

* For truncated lognormal and truncated normal, the four values represent the input mean, standard deviation, minimum, and maximum

* For triangular, the three values represent the input minimum, mean, and maximum

**Mean Unrisked OGIP= 2.25 bcf**

**Mean Unrisked Resources= 1.27 bcf**

**COS(geological)= 19.4%**

**Mean Unrisked Resources>econ limit= 3.52 bcf**

**Pc (economic discovery)= 0.2%** ery low pobability of exceeding economic threshold

# AUSAM RESOURCES LIMITED

# UNDEVELOPED LAND VALUATION

# AUSTRALIAN PERMITS

**Effective March 31, 2004**

Prepared by
Keith M. Braaten, P.Eng.

**1046451**

# UNDEVELOPED LAND VALUATION

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# INTRODUCTION

AusAm Resources Limited (AusAm) retained Gilbert Laustsen Jung Associates Ltd. (GLJ) to prepare a valuation of their undeveloped land holdings in Australia. AusAm holds interests in the following permits in Australia:

| State | Permit | Equity Interest | Area |
|---|---|---|---|
| **Queensland** | ATP 470P | 35%<br>(option to earn up to 45%)<br>excluding PL 71 area | 405 $km^2$<br>(85,000 acres) |
| | PL 71 | 0%<br>(pending - option to earn 33%) | 72 $km^2$<br>(15,000 acres) |
| | ATP 682P | 25% | 75 $km^2$<br>(18,500 acres) |
| | ATP 754P | 50% | 6,102 $km^2$<br>(1,507,000 acres) |
| | PL 101 | 0%<br>(pending - option to earn 50%) | 241 $km^2$<br>(60,000 acres) |
| | PL 176 | 0%<br>(pending - option to earn 50%) | 213 $km^2$<br>(53,000 acres) |
| **Victoria** | PEP166 | 50% | 3,551 $km^2$<br>(877,000 acres) |
| **Western Australia** | EP23 | 100% | 592 $km^2$<br>(146,000 acres) |
| | EP414 | 51.814% | 1,110 $km^2$<br>(274,000 acres) |
| | EP321 | 92.5% | 1,924 $km^2$<br>(475,250 acres) |
| | EP407 | 92.5% | 1,924 $km^2$<br>(475,250 acres) |

By definition, undeveloped lands are those lands that have not shown definite proved or probable reserves potential as a result of regional development and/or exploration activities as of the effective date.

GLJ conducted an extensive review of the exploration prospects identified in the permits located in Queensland as discussed in the section titled Assessment of Potential Resources. Based on the seismic and well information currently available for the Queensland permits, GLJ was unable to

establish a positive expected monetary value for the identified exploration prospects. In addition, there was insufficient information available to properly describe the potential stratigraphic targets of the Tinowon Formation.

Value assignments for the permits consider the acquisition cost of the permit, current work commitments related to the permit, recent farm-in agreements related to the permit, offers to purchase interests in the permit and recent exploration and development activities in nearby permits.

## SUMMARY

Undeveloped land value assignments for each permit are summarized as follows:

| State | Permit | Equity | Net Value ($) |
|---|---|---|---|
| **Queensland** | ATP 470P | 35% | 3,065,000 |
| | PL 71 | 0% | 0 |
| | ATP 682P | 25% | 849,688 |
| | ATP 754P | 50% | 2,325,000 |
| | PL 101 | 0% | 0 |
| | PL 176 | 0% | 0 |
| **Victoria** | PEP166 | 50% | 830,000 |
| **Western Australia** | EP23 | 100% | 1,250,000 |
| | EP414 | 51.814% | 863,567 |
| | EP321/407 | 92.5% | 2,000,000 |
| **Total** | | | 11,183,255 |

## DISCUSSION

Undeveloped land value assignments have been established for each permit as discussed in the following sections.

### ATP 470P

AusAm entered into a farm-in agreement with Origin Energy Resources Limited (Origin), Angari Pty Limited and Santos Exploration Pty Limited relating to Authority to Prospect for Petroleum Number 470P (ATP 470P). The terms of the agreement are described in the following paragraphs.

AusAm has exercised its option to earn a 35 percent equity interest in a portion of ATP 470P, hereinafter referred to as Formosa Downs Farm-in Area by investing $1,500,000 to drill the Weribone-2 well. As of the effective date of this report the Weribone-2 well has been drilled and cased to the top of the Showgrounds Formation. It is planned to drill ahead underbalanced through the prospective Showgrounds and Basal Rewan Formations in April 2004 when a coiled tubing unit is expected to be available.

Under the terms of the farmout agreement AusAm has an option to earn an additional equity interest in the Formosa Downs Farm-in Area at the rate of one percent per $100,000 of investment to a maximum additional 10 percent by investing an additional $1,000,000. It is likely that AusAm will fund the completion and tie-in costs of the Weribone-2 well, estimated at $650,000, thereby earning an additional 6.5 percent equity interest.

As part of the farm-in agreement, AusAm also has the option to earn equity interest in Production License 71 (PL 71) in two phases. PL 71 contains the Parknook and Namarah Fields that are currently producing gas from the Showgrounds and Basal Rewan Formations. In the first phase, AusAm is required to invest $5,000,000 to drill wells Parknook-7 and Namarah-7 to earn a 33 percent equity interest in PL 71. In the second phase, AusAm is required to invest an additional $2,500,000 to drill one additional well to earn a total equity interest of 50 percent in PL 71.

In addition to the investment of $1,500,000 to earn a 35 percent equity interest in the Formosa Downs Farm-in Area, AusAm traded 50 percent of their 100 percent equity interest in ATP 754P to Origin for the right to participate in the farm-in agreements on ATP 470P and ATP 682P. The

traded equity interest from ATP 754P is considered to be part of the purchase price for ATP 470P and is estimated to be $2,075,000. The traded value has been split between ATP 470P and ATP 682P on a new acreage basis.

Based on the foregoing, the undeveloped land value for AusAm's interests in ATP 470P is estimated to be $3,575,000, which is the sum of the traded value from ATP 754P and the farmin investment.

GLJ has assigned probable reserves to the Weribone-2 well with a net present value discounted at 10 percent of $510,000 attributable to AusAm's interest. The area immediately surrounding the Weribone-2 well will be converted to a production license. GLJ estimates the undeveloped land value for the remainder of the Formosa Downs Farm-in Area to be $3,065,000, which is the total undeveloped land value less the value attributed to the Weribone-2 well.

**ATP 682P**

AusAm has participated in a farm-in agreement with Origin on Authority to Prospect for Petroleum Number 682P (ATP 682P). Under the terms of the farm-in agreement AusAm and Origin funded 100 percent of the cost to drill an exploration well to earn an 80 percent equity interest in ATP 682P. AusAm's equity interest is 25 percent. The well Palmerston-1 has been drilled and cased at a cost of $1,919,324 ($599,688 net to AusAm). The well is currently waiting on completion and GLJ has assigned possible reserves to an untested interval in the well.

GLJ estimates the undeveloped land value for ATP 682P to be $849,688, which is the sum of the investment in Palmerston-1 and the value of $250,000 attributed to the interests traded from ATP 754P to participate in the farm-in agreement.

**ATP 754P**

AusAm was granted 100 percent of the Authority to Prospect for Petroleum Number 754P (ATP 754P) for a term of four years commencing on August 1, 2003. The permit includes 81 blocks covering an area totaling 6,102 $km^2$ (1,507,000 acres). Under the terms of the agreement AusAm will relinquish 20 blocks on August 1, 2005 and 20 blocks on August 1, 2006.

The work commitment for ATP 754P is summarized as follows:

| | |
|---|---|
| Year ending August 1, 2004 | $1,550,000 |
| Year ending August 1, 2005 | $1,500,000 |
| Year ending August 1, 2006 | $100,000 |
| Year ending August 1, 2007 | $1,500,000 |
| Total | $4,650,000 |

Subsequent to being granted the permit, AusAm traded a 50 percent interest in the block to Origin for an extension of the farm-in agreement on ATP 470P that includes access to Origin's facilities and transportation infrastructure in the area and the right to participate on the same farm-in terms as Origin received for ATP 682P.

GLJ assigns a value of $2,325,000 to AusAm's 50 percent interest in ATP 754P based on the work commitment.

The undeveloped land value attributed to ATP 754P may be further enhanced by recent activities on the adjacent ATP 645P. As announced in June 2003, Sunshine Gas Limited (Sunshine) and Samson-International (Australia) Pty. Ltd. (Samson) entered into an agreement where Samson would earn interest of 50 to 60 percent by investing up to $10,550,000 in Sunshine's permits in Queensland. The majority of the investment is being directed towards ATP 645P. In September 2003, the well Overston-1 was completed over an interval of 24 metres and tested gas at 250 MCFD with condensate from the Upper Tinowon Formation. Sunshine has interpreted the zone to be damaged by drilling fluids since the well was drilled significantly overbalanced. Sunshine announced that the processing and interpretation of the recently acquired 3D seismic survey has been completed and that the well Overston-2 was spudded on March 21, 2004. Sunshine indicated that the Overston-2 well would be drilled underbalanced to minimize formation damage, a practice that has been used successfully by Origin and Mosaic Oil NL in other Permian Tinowon sandstone reservoirs.

**PEP 166**

AusAm currently holds a 50 percent equity interest in Petroleum Exploration Permit (166 PEP) 166 located in Victoria, as shown on Map I-3. AusAm has identified the Warrugel prospect on PEP 166.

The work commitment for PEP 166 is summarized as follows:

| | |
|---|---|
| Year ending January 2004 | $60,000 |
| Year ending January 2005 | $200,000 |
| Year ending January 2006 | $1,000,000 |
| Year ending January 2007 | $300,000 |
| Year ending January 2008 | $100,000 |
| Total | $1,660,000 |

There are no pending agreements relating to PEP 166. A farm-in agreement was recently proposed for the Trifon Tight Gas Project on the adjacent PEP 157. Under the proposed farmout agreement, the farmee would fund 100 percent of the cost, estimated at $5,000,000, to drill one well and earn 50 percent interest in the project. The project earning rate is $100,000 per percent.

The cost of a well targeting the Warrugel prospect is estimated at $2,000,000. Under similar terms as PEP 157, drill one well to earn 50 percent equity interest, the earning rate is $40,000 per percent. Under these terms AusAm's residual equity interest of 25 percent in PEP 166 would have a value of $1,000,000.

GLJ assigns a value of $830,000 to AusAm's 50 percent interest in PEP 166 based on the work commitment.

**EP 23**

AusAm currently holds a 100 percent equity interest in Exploration Permit 23 (EP 23) located in Western Australia. As shown on Map Index 2, there are two tracts of land included in EP 23. AusAm has identified two prospects on EP 23.

AusAm has received a proposal from Black Rock to farm-in on AusAm's interests in EP 23. Under the proposed farmout agreement, Black Rock would fund 100 percent of the cost, estimated at $5,000,000, to drill one well and earn 80 percent interest in the permit. AusAm would retain a residual equity interest of 20 percent in the permit.

GLJ has assigned a value of $1,250,000 to AusAm's residual equity interest of 20 percent in EP 23 based on the farm-in earning rate of $62,500 per percent of equity interest.

**EP 414**

AusAm currently holds a 51.814 percent equity interest in Exploration Permit 414 (EP 414) located in Western Australia. As shown on Map Index 2, there are three tracts of land included in EP 414. Saitta Petroleum Consultants Pty. Ltd. (SPCPL) of Australia conducted a prospectivity review of EP 414(1) for AusAm. The review identified one prospect and three leads in Permian Age sandstone formations with expected undiscovered gas resources of 186.4 BCF. AusAm identified an additional prospect on EP 414(2).

GLJ has not conducted an independent assessment of the undiscovered resources for this permit.

AusAm has received a proposal from Black Rock to farm-in on AusAm's interests in EP 414. Under the proposed farmout agreement, Black Rock would fund 100 percent of the cost, estimated at $5,000,000, to drill one well and earn 75 percent interest in the permit. AusAm would retain a residual equity interest of 12.9535 percent in the permit.

GLJ has assigned a value of $863,567 to AusAm's residual equity interest of 12.9535 percent in EP 414 based on the farm-in earning rate of $66,667 per percent of equity interest.

**EP 321/407**

AusAm holds a 92.5 percent equity interest in Exploration Permits 321 and 407 (EP 321 and EP 407) located in Western Australia. The explorations prospects contain the Warro structure that straddles the border between EP 321 and EP 407 and the Dandaragan Deep Prospect located in EP 321.

The main reservoir in the Warro structure is in the Late Jurassic Yarragadee Formation and has been penetrated by two wells. The Warro-1 well was drilled in 1977, experienced operational difficulties and did not flow significant quantities of gas. The Warro-2 well was drilled as a follow-up well approximately 225 metres away and tested gas at rates up to 104 MCFD following fracture stimulation. Both wells encountered a gas-bearing interval with a gross thickness of approximately 490 metres containing interbedded low permeability sandstone and claystone. It is speculated that underbalanced drilling is required to mitigate formation damage and achieve commercial flow rates from the reservoir.

The permits are currently up for renewal with the following work commitments awaiting approval by the Department of Industry and Resources:

| | EP 321<br>$ | EP 407<br>$ |
|---|---|---|
| Year 1 | 150,000 | 1,500,000 |
| Year 2 | 500,000 | 1,000,000 |
| Year 3 | 150,000 | 150,000 |
| Year 4 | 5,000,000 | 5,000,000 |
| Year 5 | 150,000 | 150,000 |
| Totals | 5,950,000 | 7,800,000 |

AusAm has entered into a Sale and Purchase Agreement to sell their interests in the two permits for the purchase price of $2,000,000. The agreement was made on January 30, 2004. Under the agreement the transaction is to close no later than June 30, 2004.

GLJ has assigned a value of $2,000,000 to AusAm's 92.5 percent interest in EP 321 and EP 407 based on the terms of the Sale and Purchase Agreement.

# CONSTANT PRICE ANALYSIS

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# Summary of Reserves and Values

Company: **AusAm Resources Limited**
Property: **Queensland**

Pricing: **Posted Mar. 31, 2004**
Effective Date: **March 31, 2004**

| | Total Proved Plus Probable | Total PPP |
|---|---|---|
| **MARKETABLE RESERVES** | | |
| **Gas - MMCF** | | |
| Gross Lease | 3159 | 7217 |
| Total Company Interest | 1311 | 2989 |
| Net After Royalty | 1172 | 2673 |
| **Natural Gas Liquids - MSTB** | | |
| Gross Lease | 27 | 87 |
| Total Company Interest | 11 | 32 |
| Net After Royalty | 10 | 28 |
| **Oil Equivalent - MBOE** | | |
| Gross Lease | 553 | 1290 |
| Total Company Interest | 230 | 530 |
| Net After Royalty | 205 | 474 |
| **BEFORE TAX PRESENT VALUE - $M** | | |
| 0.0% | 1007 | 2984 |
| 5.0% | 735 | 2323 |
| 8.0% | 603 | 2004 |
| 10.0% | 526 | 1816 |
| 12.0% | 456 | 1646 |
| 15.0% | 362 | 1420 |
| 20.0% | 233 | 1106 |
| **FIRST 6 YEARS BEFORE TAX CASH FLOW - $M** | | |
| 2004 (9 Months) | -1017 | -1060 |
| 2005 | 596 | 59 |
| 2006 | 432 | 1354 |
| 2007 | 313 | 931 |
| 2008 | 227 | 643 |
| 2009 | 163 | 442 |

Oil Equivalent Factors:

Sales Gas - 6.0 mcf/boe  Condensate - 1.0 bbl/boe

# Company Production, Reserves and Present Value Summary

Company: **AusAm Resources Limited**
Property: **Queensland**

Reserve Class: **Proved Plus Probable**
Development Class: **Total**
Pricing: **Posted Mar. 31, 2004**
Effective Date: **March 31, 2004**

| Entity Description | 2004 Company Interest Prod'n Gas mcf/d | Oil bbl/d | NGL bbl/d | BOE bbl/d | Company Interest Reserves Gas Mmcf | Oil Mbbl | NGL Mbbl | Sulphur Mlt | BOE Mbbl | Net After Royalty Reserves Gas Mmcf | Oil Mbbl | NGL Mbbl | Sulphur Mlt | BOE Mbbl | Reserve Life Index Yrs | Before Income Tax Discounted Present Value M$ 0% | 10% | 12% | 15% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Palmerston*** | | | | | | | | | | | | | | | | | | | |
| ***Total Palmerston*** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 0 | 0 | 0 | 0 |
| ***Weribone*** | | | | | | | | | | | | | | | | | | | |
| ***Weribone 2*** | | | | | | | | | | | | | | | | | | | |
| Basal Rewan | 244 | 0 | 2 | 43 | 407 | 0 | 3 | 0 | 71 | 363 | 0 | 3 | 0 | 64 | 4.6 | 776 | 608 | 583 | 549 |
| Showgrounds | 491 | 0 | 4 | 86 | 905 | 0 | 8 | 0 | 158 | 808 | 0 | 7 | 0 | 142 | 5.1 | 1631 | 1269 | 1214 | 1142 |
| ***Other Revenue and Expenses*** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | -1400 | -1351 | -1342 | -1329 |
| ***Total Weribone 2*** | 734 | 0 | 6 | 129 | 1311 | 0 | 11 | 0 | 230 | 1172 | 0 | 10 | 0 | 205 | 4.9 | 1007 | 526 | 456 | 362 |
| ***Weribone 3*** | | | | | | | | | | | | | | | | | | | |
| ***Total Weribone 3*** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 0 | 0 | 0 | 0 |
| ***Total Weribone*** | 734 | 0 | 6 | 129 | 1311 | 0 | 11 | 0 | 230 | 1172 | 0 | 10 | 0 | 205 | 4.9 | 1007 | 526 | 456 | 362 |
| ***Queensland*** | 734 | 0 | 6 | 129 | 1311 | 0 | 11 | 0 | 230 | 1172 | 0 | 10 | 0 | 205 | 4.9 | 1007 | 526 | 456 | 362 |

**BOE Factors:**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| OIL | 1.00000 | RES GAS | 6.00000 | PROPANE | 1.00000 | ETHANE | 1.00000 |
| COND | 1.00000 | SLN GAS | 6.00000 | BUTANE | 1.00000 | SULPHUR | 0.00000 |

p:/s1046451/rems/econ/Posted_Mar._31_2004/Queensland_RC09_crv.htm

# Company Production, Reserves and Present Value Summary

Company: **AusAm Resources Limited**
Property: **Queensland**

Reserve Class: **Total**
Development Class: **PPP**
Pricing: **Posted Mar. 31, 2004**
Effective Date: **March 31, 2004**

| Entity Description | 2004 Company Interest Prod'n | | | | Company Interest Reserves | | | | | Net After Royalty Reserves | | | | | Reserve Life Index Yrs | Before Income Tax Discounted Present Value M$ | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gas mcf/d | Oil bbl/d | NGL bbl/d | BOE bbl/d | Gas Mmcf | Oil Mbbl | NGL Mbbl | Sulphur Mlt | BOE Mbbl | Gas Mmcf | Oil Mbbl | NGL Mbbl | Sulphur Mlt | BOE Mbbl | | 0% | 10% | 12% | 15% |
| ***Palmerston*** | | | | | | | | | | | | | | | | | | | |
| Palmerston-1 | 0 | 0 | 0 | 0 | 323 | 0 | 9 | 0 | 63 | 291 | 0 | 8 | 0 | 57 | 999.0 | 675 | 515 | 490 | 455 |
| ***Total Palmerston*** | 0 | 0 | 0 | 0 | 323 | 0 | 9 | 0 | 63 | 291 | 0 | 8 | 0 | 57 | 999.0 | 675 | 515 | 490 | 455 |
| ***Weribone*** | | | | | | | | | | | | | | | | | | | |
| ***Weribone 2*** | | | | | | | | | | | | | | | | | | | |
| Basal Rewan | 264 | 0 | 2 | 46 | 441 | 0 | 4 | 0 | 77 | 394 | 0 | 3 | 0 | 69 | 4.6 | 841 | 660 | 632 | 596 |
| Showgrounds | 532 | 0 | 4 | 93 | 981 | 0 | 8 | 0 | 172 | 876 | 0 | 7 | 0 | 153 | 5.1 | 1769 | 1376 | 1317 | 1238 |
| ***Other Revenue and Expenses*** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | -1400 | -1351 | -1342 | -1329 |
| ***Total Weribone 2*** | 796 | 0 | 7 | 139 | 1422 | 0 | 12 | 0 | 249 | 1270 | 0 | 11 | 0 | 222 | 4.9 | 1210 | 684 | 607 | 505 |
| ***Weribone 3*** | | | | | | | | | | | | | | | | | | | |
| Weribone-3 Basal Rewan | 0 | 0 | 0 | 0 | 386 | 0 | 3 | 0 | 68 | 345 | 0 | 3 | 0 | 60 | 999.0 | 736 | 540 | 510 | 471 |
| Weribone-3 Showgrounds | 0 | 0 | 0 | 0 | 858 | 0 | 7 | 0 | 150 | 767 | 0 | 6 | 0 | 134 | 999.0 | 1541 | 1123 | 1061 | 978 |
| ***Other Revenue and Expenses*** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | -1178 | -1046 | -1023 | -990 |
| ***Total Weribone 3*** | 0 | 0 | 0 | 0 | 1244 | 0 | 10 | 0 | 218 | 1112 | 0 | 9 | 0 | 195 | 999.0 | 1099 | 617 | 549 | 460 |
| ***Total Weribone*** | 796 | 0 | 7 | 139 | 2666 | 0 | 22 | 0 | 467 | 2382 | 0 | 20 | 0 | 417 | 9.2 | 2310 | 1301 | 1156 | 965 |
| ***Queensland*** | 796 | 0 | 7 | 139 | 2989 | 0 | 32 | 0 | 530 | 2673 | 0 | 28 | 0 | 474 | 10.4 | 2984 | 1816 | 1646 | 1420 |

**BOE Factors:**

| | | | | | | |
|---|---|---|---|---|---|---|
| OIL | 1.00000 | RES GAS | 6.00000 | PROPANE | 1.00000 | ETHANE | 1.00000 |
| COND | 1.00000 | SLN GAS | 6.00000 | BUTANE | 1.00000 | SULPHUR | 0.00000 |

p:/s1046451/rems/econ/Posted_Mar._31_2004/Queensland_RC35_crv.htm

# Economic Forecast

Company: **AusAm Resources Limited**
Property: **Queensland**

Reserve Class: **Proved Plus Probable**
Development Class: **Total**
Pricing: **Posted Mar. 31, 2004**
Effective Date: **March 31, 2004**

## PRODUCTION FORECAST

| | | Residue Gas Production | | | | | Condensate Production | | | | | Total Oil Equiv. Production | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Gross Gas Wells | Gross Daily Mcf | Compny Daily Mcf | Compny Yearly Mmcf | Net Yearly Mmcf | Price $/Mcf | Gross Daily Stb | Compny Daily Stb | Compny Yearly Stb | Net Yearly Stb | Price $/Bbl | Gross Daily Stb | Compny Daily Stb | Compny Yearly Stb | Net Yearly Stb | Price $/BOE |
| 2004 | 1 | 1770 | 734 | 201 | 180 | 2.01 | 15 | 6 | 1693 | 1513 | 35.54 | 310 | 129 | 35199 | 31454 | 13.19 |
| 2005 | 1 | 2078 | 862 | 315 | 281 | 2.01 | 17 | 7 | 2651 | 2369 | 35.54 | 364 | 151 | 55112 | 49248 | 13.19 |
| 2006 | 1 | 1511 | 627 | 229 | 205 | 2.01 | 13 | 5 | 1927 | 1722 | 35.54 | 265 | 110 | 40072 | 35809 | 13.19 |
| 2007 | 1 | 1099 | 456 | 166 | 149 | 2.01 | 9 | 4 | 1402 | 1252 | 35.54 | 192 | 80 | 29141 | 26040 | 13.19 |
| 2008 | 1 | 801 | 332 | 121 | 108 | 2.01 | 7 | 3 | 1022 | 913 | 35.54 | 140 | 58 | 21244 | 18984 | 13.19 |
| 2009 | 1 | 581 | 241 | 88 | 79 | 2.01 | 5 | 2 | 741 | 662 | 35.54 | 102 | 42 | 15404 | 13765 | 13.19 |
| 2010 | 1 | 423 | 175 | 64 | 57 | 2.01 | 4 | 1 | 539 | 482 | 35.54 | 74 | 31 | 11207 | 10015 | 13.19 |
| 2011 | 1 | 307 | 128 | 47 | 42 | 2.01 | 3 | 1 | 392 | 350 | 35.54 | 54 | 22 | 8155 | 7287 | 13.19 |
| 2012 | 1 | 224 | 93 | 34 | 30 | 2.01 | 2 | 1 | 286 | 256 | 35.54 | 39 | 16 | 5948 | 5315 | 13.19 |
| 2013 | 1 | 137 | 57 | 21 | 19 | 2.01 | 1 | 0 | 175 | 156 | 35.54 | 24 | 10 | 3631 | 3244 | 13.19 |
| 2014 | 1 | 85 | 35 | 13 | 12 | 2.01 | 1 | 0 | 109 | 97 | 35.54 | 15 | 6 | 2267 | 2026 | 13.19 |
| 2015 | 1 | 63 | 26 | 9 | 8 | 2.01 | 1 | 0 | 80 | 71 | 35.54 | 11 | 5 | 1662 | 1486 | 13.19 |
| Sub. | 1 | 735 | 305 | 1308 | 1169 | 2.01 | 6 | 3 | 11016 | 9844 | 35.54 | 129 | 53 | 229042 | 204672 | 13.19 |
| Rem. | 1 | 50 | 21 | 3 | 3 | 2.01 | 0 | 0 | 25 | 22 | 35.54 | 9 | 4 | 510 | 456 | 13.19 |
| **Tot.** | **1** | **713** | **296** | **1311** | **1172** | **2.01** | **6** | **2** | **11041** | **9866** | **35.54** | **125** | **52** | **229552** | **205128** | **13.19** |

## REVENUE AND EXPENSE FORECAST

| | Revenue Before Burdens | | | | | | Royalty Burdens Pre-Processing | | Gas Processing Allowance | | Total Royalty After Process. | Net Revenue After Royalty | Operating Expenses | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Working Interest | | | Royalty | Company | | | | | | | | | |
| Year | Oil M$ | Gas M$ | NGL+Sul M$ | Total M$ | Interest M$ | Total M$ | Crown M$ | Other M$ | Crown M$ | Other M$ | M$ | M$ | Fixed M$ | Variable M$ | Total M$ |
| 2004 | 0 | 404 | 60 | 464 | 0 | 464 | 46 | 3 | 0 | 0 | 49 | 415 | 1 | 0 | 1 |
| 2005 | 0 | 633 | 94 | 727 | 0 | 727 | 73 | 5 | 0 | 0 | 77 | 650 | 5 | 0 | 5 |
| 2006 | 0 | 460 | 68 | 529 | 0 | 529 | 53 | 3 | 0 | 0 | 56 | 472 | 5 | 0 | 5 |
| 2007 | 0 | 335 | 50 | 384 | 0 | 384 | 38 | 2 | 0 | 0 | 41 | 343 | 5 | 0 | 5 |
| 2008 | 0 | 244 | 36 | 280 | 0 | 280 | 28 | 2 | 0 | 0 | 30 | 250 | 5 | 0 | 5 |
| 2009 | 0 | 177 | 26 | 203 | 0 | 203 | 20 | 1 | 0 | 0 | 22 | 182 | 5 | 0 | 5 |
| 2010 | 0 | 129 | 19 | 148 | 0 | 148 | 15 | 1 | 0 | 0 | 16 | 132 | 5 | 0 | 5 |
| 2011 | 0 | 94 | 14 | 108 | 0 | 108 | 11 | 1 | 0 | 0 | 11 | 96 | 5 | 0 | 5 |
| 2012 | 0 | 68 | 10 | 78 | 0 | 78 | 8 | 1 | 0 | 0 | 8 | 70 | 5 | 0 | 5 |
| 2013 | 0 | 42 | 6 | 48 | 0 | 48 | 5 | 0 | 0 | 0 | 5 | 43 | 5 | 0 | 5 |
| 2014 | 0 | 26 | 4 | 30 | 0 | 30 | 3 | 0 | 0 | 0 | 3 | 27 | 5 | 0 | 5 |
| 2015 | 0 | 19 | 3 | 22 | 0 | 22 | 2 | 0 | 0 | 0 | 2 | 20 | 5 | 0 | 5 |
| Sub. | 0 | 2629 | 392 | 3021 | 0 | 3021 | 302 | 19 | 0 | 0 | 321 | 2699 | 56 | 0 | 56 |
| Rem. | 0 | 6 | 1 | 7 | 0 | 7 | 1 | 0 | 0 | 0 | 1 | 6 | 2 | 0 | 2 |
| **Tot.** | **0** | **2635** | **392** | **3028** | **0** | **3028** | **303** | **19** | **0** | **0** | **322** | **2705** | **58** | **0** | **58** |
| Disc | 0 | 2022 | 301 | 2324 | 0 | 2324 | 232 | 15 | 0 | 0 | 247 | 2076 | 33 | 0 | 33 |

| | Other Expenses | | | Net Prod'n | Other Income | | | | Net Capital Investment | | | | Before Tax Cash Flow | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Mineral Tax M$ | Capital Tax M$ | NPI Payment M$ | Revenue M$ | Other M$ | ARTC M$ | Aband. Costs M$ | Oper. Income M$ | Dev. M$ | Plant M$ | Tang. M$ | Total M$ | Annual M$ | Cum. M$ | 10% Dcf M$ |
| 2004 | 0 | 0 | 31 | 383 | 0 | 0 | 0 | 383 | 1000 | 400 | 0 | 1400 | -1017 | -1017 | -982 |
| 2005 | 0 | 0 | 48 | 596 | 0 | 0 | 0 | 596 | 0 | 0 | 0 | 0 | 596 | -421 | -452 |
| 2006 | 0 | 0 | 35 | 432 | 0 | 0 | 0 | 432 | 0 | 0 | 0 | 0 | 432 | 11 | -104 |
| 2007 | 0 | 0 | 25 | 313 | 0 | 0 | 0 | 313 | 0 | 0 | 0 | 0 | 313 | 324 | 126 |
| 2008 | 0 | 0 | 18 | 227 | 0 | 0 | 0 | 227 | 0 | 0 | 0 | 0 | 227 | 551 | 277 |
| 2009 | 0 | 0 | 13 | 163 | 0 | 0 | 0 | 163 | 0 | 0 | 0 | 0 | 163 | 714 | 376 |
| 2010 | 0 | 0 | 10 | 118 | 0 | 0 | 0 | 118 | 0 | 0 | 0 | 0 | 118 | 832 | 441 |
| 2011 | 0 | 0 | 7 | 84 | 0 | 0 | 0 | 84 | 0 | 0 | 0 | 0 | 84 | 916 | 484 |
| 2012 | 0 | 0 | 5 | 60 | 0 | 0 | 0 | 60 | 0 | 0 | 0 | 0 | 60 | 977 | 511 |
| 2013 | 0 | 0 | 3 | 35 | 0 | 0 | 0 | 35 | 0 | 0 | 0 | 0 | 35 | 1012 | 525 |
| 2014 | 0 | 0 | 2 | 20 | 0 | 0 | 0 | 20 | 0 | 0 | 0 | 0 | 20 | 1032 | 533 |
| 2015 | 0 | 0 | 1 | 14 | 0 | 0 | 0 | 14 | 0 | 0 | 0 | 0 | 14 | 1045 | 538 |
| Sub. | 0 | 0 | 198 | 2445 | 0 | 0 | 0 | 2445 | 1000 | 400 | 0 | 1400 | 1045 | 1045 | 14 |
| Rem. | 0 | 0 | 0 | 4 | 0 | 0 | 42 | -38 | 0 | 0 | 0 | 0 | -38 | 1007 | 1007 |
| **Tot.** | **0** | **0** | **199** | **2449** | **0** | **0** | **42** | **2407** | **1000** | **400** | **0** | **1400** | **1007** | **1007** | **526** |
| Disc | 0 | 0 | 153 | 1890 | 0 | 0 | 13 | 1877 | 965 | 386 | 0 | 1351 | 526 | 526 | 526 |

## RESERVE SUMMARY

| | | Remaining Reserves at April 1, 2004 | | | | | Oil Equivalents | | | Reserve Life Indic. (yr) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Product** | Units | Gross | Working Interest | Roy/NPI Interest | Total Company | Net | BOE Factor | Company Mstb | % of Total | Reserve Life | Life Index | Half Life |
| Residue Gas | Mmcf | 3159 | 1311 | 0 | 1311 | 1172 | 6.000 | 219 | 95 | 12.1 | 4.9 | 2.4 |
| | MMMBtu | 3159 | 1311 | 0 | 1311 | 1172 | | | | 12.1 | 4.9 | 2.4 |
| Condensate | Mstb | 27 | 11 | 0 | 11 | 10 | 1.000 | 11 | 5 | 12.1 | 4.9 | 2.4 |
| Total Oil Eq. | Mstb | 553 | 230 | 0 | 230 | 205 | | 230 | 100 | 12.1 | 4.9 | 2.4 |

## PRODUCT REVENUE AND EXPENSES

| | | Average First Year Unit Values | | | | | | | Net Revenue After Royalties | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Product** | Units | Base Price | Price Adjust. | Wellhead Price | Net Burdens | Operating Expenses | Other Expenses | Prod'n Revenue | Undisc M$ | % of Total | 10% Disc M$ | % of Total |
| Residue Gas | $/Mcf | 2.95 | -0.94 | 2.01 | 0.21 | 0.01 | 0.00 | 1.79 | 2355 | 87 | 1807 | 87 |
| Condensate | $/Stb | 35.54 | 0.00 | 35.54 | 3.78 | 0.10 | 0.00 | 31.66 | 351 | 13 | 269 | 13 |
| Total Oil Eq. | $/BOE | 18.56 | -5.37 | 13.19 | 1.40 | 0.04 | 0.00 | 11.75 | 2705 | 100 | 2076 | 100 |

## INTEREST AND NET PRESENT VALUE SUMMARY

| Revenue Interests and Burdens (%) | | |
|---|---|---|
| | Initial | Average |
| Working Interest | 41.5000 | 41.5000 |
| Capital Interest | 100.0000 | 100.0000 |
| Royalty Interest | 0.0000 | 0.0000 |
| Crown Royalty | 10.0000 | 10.0000 |
| Non-crown Royalty | 0.6400 | 0.6400 |
| Mineral Tax | 0.0000 | 0.0000 |
| NPI Payment | 7.5000 | 7.6194 |

| | Net Present Value Before Income Tax | | | | |
|---|---|---|---|---|---|
| Disc. Rate % | Prod'n Revenue M$ | Operating Income M$ | Capital Invest. M$ | Cash Flow M$ | Cash Flow $/BOE |
| 0.0 | 2449 | 2407 | 1400 | 1007 | 4.39 |
| 5.0 | 2132 | 2110 | 1375 | 735 | 3.20 |
| 8.0 | 1980 | 1963 | 1360 | 603 | 2.63 |
| 10.0 | 1890 | 1877 | 1351 | 526 | 2.29 |
| 12.0 | 1808 | 1798 | 1342 | 456 | 1.99 |
| 15.0 | 1698 | 1691 | 1329 | 362 | 1.58 |
| 20.0 | 1544 | 1540 | 1307 | 233 | 1.01 |

Project.....1046451
Entity.....Queensland (Total Proved Plus Probable)
Evaluator...Braaten, Keith M.

# Economic Forecast

Company: **AusAm Resources Limited**
Property: **Queensland**

Reserve Class: **Total**
Development Class: **PPP**
Pricing: **Posted Mar. 31, 2004**
Effective Date: **March 31, 2004**

## PRODUCTION FORECAST

| | | Residue Gas Production | | | | | Condensate Production | | | | | Total Oil Equiv. Production | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Gross Gas Wells | Gross Daily Mcf | Compny Daily Mcf | Compny Yearly Mmcf | Net Yearly Mmcf | Price $/Mcf | Gross Daily Stb | Compny Daily Stb | Compny Yearly Stb | Net Yearly Stb | Price $/Bbl | Gross Daily Stb | Compny Daily Stb | Compny Yearly Stb | Net Yearly Stb | Price $/BOE |
| 2004 | 1 | 1770 | 796 | 218 | 195 | 2.01 | 15 | 7 | 1836 | 1640 | 35.54 | 310 | 139 | 38167 | 34106 | 13.19 |
| 2005 | 3 | 4591 | 1826 | 666 | 596 | 2.03 | 63 | 21 | 7802 | 6992 | 35.54 | 828 | 326 | 118870 | 106359 | 13.71 |
| 2006 | 3 | 4547 | 1836 | 670 | 600 | 2.03 | 59 | 21 | 7557 | 6770 | 35.54 | 817 | 327 | 119272 | 106700 | 13.64 |
| 2007 | 3 | 3127 | 1278 | 466 | 417 | 2.03 | 39 | 14 | 5108 | 4575 | 35.54 | 560 | 227 | 82831 | 74091 | 13.59 |
| 2008 | 3 | 2163 | 893 | 326 | 292 | 2.02 | 26 | 10 | 3476 | 3113 | 35.54 | 387 | 158 | 57821 | 51715 | 13.55 |
| 2009 | 3 | 1493 | 623 | 227 | 203 | 2.02 | 18 | 6 | 2364 | 2116 | 35.54 | 266 | 110 | 40249 | 35995 | 13.51 |
| 2010 | 3 | 889 | 399 | 146 | 130 | 2.01 | 8 | 3 | 1234 | 1102 | 35.54 | 156 | 70 | 25532 | 22816 | 13.20 |
| 2011 | 2 | 630 | 283 | 103 | 92 | 2.01 | 5 | 2 | 871 | 778 | 35.54 | 110 | 50 | 18105 | 16178 | 13.19 |
| 2012 | 2 | 449 | 202 | 74 | 66 | 2.01 | 4 | 2 | 621 | 555 | 35.54 | 79 | 35 | 12906 | 11532 | 13.19 |
| 2013 | 2 | 263 | 118 | 43 | 39 | 2.01 | 2 | 1 | 364 | 325 | 35.54 | 46 | 21 | 7559 | 6755 | 13.19 |
| 2014 | 2 | 164 | 74 | 27 | 24 | 2.01 | 1 | 1 | 227 | 202 | 35.54 | 29 | 13 | 4710 | 4209 | 13.19 |
| 2015 | 2 | 113 | 51 | 19 | 17 | 2.01 | 1 | 0 | 156 | 139 | 35.54 | 20 | 9 | 3241 | 2896 | 13.19 |
| Sub. | 2 | 1681 | 696 | 2986 | 2670 | 2.02 | 20 | 7 | 31614 | 28309 | 35.54 | 300 | 123 | 529263 | 473353 | 13.54 |
| Rem. | 1 | 50 | 23 | 3 | 3 | 2.01 | 0 | 0 | 27 | 24 | 35.54 | 9 | 4 | 553 | 494 | 13.19 |
| **Tot.** | **2** | **1630** | **675** | **2989** | **2673** | **2.02** | **20** | **7** | **31640** | **28333** | **35.54** | **291** | **120** | **529816** | **473847** | **13.54** |

## REVENUE AND EXPENSE FORECAST

| | Revenue Before Burdens | | | | | | Royalty Burdens Pre-Processing | | Gas Processing Allowance | | Total Royalty After Process. | Net Revenue After Royalty | Operating Expenses | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Working Interest | | | | | | | | | | | | | |
| Year | Oil M$ | Gas M$ | NGL+Sul M$ | Total M$ | Royalty Interest M$ | Company Total M$ | Crown M$ | Other M$ | Crown M$ | Other M$ | M$ | M$ | Fixed M$ | Variable M$ | Total M$ |
| 2004 | 0 | 438 | 65 | 503 | 0 | 503 | 50 | 3 | 0 | 0 | 54 | 450 | 1 | 0 | 1 |
| 2005 | 0 | 1353 | 277 | 1630 | 0 | 1630 | 163 | 8 | 0 | 0 | 171 | 1459 | 10 | 0 | 10 |
| 2006 | 0 | 1359 | 269 | 1627 | 0 | 1627 | 163 | 8 | 0 | 0 | 171 | 1456 | 14 | 0 | 14 |
| 2007 | 0 | 944 | 182 | 1126 | 0 | 1126 | 113 | 6 | 0 | 0 | 119 | 1007 | 14 | 0 | 14 |
| 2008 | 0 | 660 | 124 | 783 | 0 | 783 | 78 | 4 | 0 | 0 | 83 | 701 | 14 | 0 | 14 |
| 2009 | 0 | 460 | 84 | 544 | 0 | 544 | 54 | 3 | 0 | 0 | 57 | 486 | 14 | 0 | 14 |
| 2010 | 0 | 293 | 44 | 337 | 0 | 337 | 34 | 2 | 0 | 0 | 36 | 301 | 11 | 0 | 11 |
| 2011 | 0 | 208 | 31 | 239 | 0 | 239 | 24 | 2 | 0 | 0 | 25 | 213 | 11 | 0 | 11 |
| 2012 | 0 | 148 | 22 | 170 | 0 | 170 | 17 | 1 | 0 | 0 | 18 | 152 | 11 | 0 | 11 |
| 2013 | 0 | 87 | 13 | 100 | 0 | 100 | 10 | 1 | 0 | 0 | 11 | 89 | 11 | 0 | 11 |
| 2014 | 0 | 54 | 8 | 62 | 0 | 62 | 6 | 0 | 0 | 0 | 7 | 56 | 11 | 0 | 11 |
| 2015 | 0 | 37 | 6 | 43 | 0 | 43 | 4 | 0 | 0 | 0 | 5 | 38 | 10 | 0 | 10 |
| Sub. | 0 | 6040 | 1124 | 7164 | 0 | 7164 | 716 | 39 | 0 | 0 | 756 | 6408 | 131 | 0 | 131 |
| Rem. | 0 | 6 | 1 | 7 | 0 | 7 | 1 | 0 | 0 | 0 | 1 | 7 | 2 | 0 | 2 |
| **Tot.** | **0** | **6047** | **1125** | **7171** | **0** | **7171** | **717** | **39** | **0** | **0** | **757** | **6415** | **133** | **0** | **133** |
| Disc | 0 | 4536 | 853 | 5388 | 0 | 5388 | 539 | 29 | 0 | 0 | 568 | 4820 | 78 | 0 | 78 |

| | Other Expenses | | | Net Prod'n Revenue | Other Income | | Aband. Costs | Oper. Income | Net Capital Investment | | | | Before Tax Cash Flow | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Mineral Tax M$ | Capital Tax M$ | NPI Payment M$ | M$ | Other M$ | ARTC M$ | M$ | M$ | Dev. M$ | Plant M$ | Tang. M$ | Total M$ | Annual M$ | Cum. M$ | 10% Dcf M$ |
| 2004 | 0 | 0 | 34 | 415 | 0 | 0 | 0 | 415 | 1075 | 400 | 0 | 1475 | -1060 | -1060 | -1023 |
| 2005 | 0 | 0 | 86 | 1363 | 0 | 0 | 0 | 1363 | 959 | 344 | 0 | 1303 | 59 | -1001 | -970 |
| 2006 | 0 | 0 | 88 | 1354 | 0 | 0 | 0 | 1354 | 0 | 0 | 0 | 0 | 1354 | 353 | 123 |
| 2007 | 0 | 0 | 62 | 931 | 0 | 0 | 0 | 931 | 0 | 0 | 0 | 0 | 931 | 1285 | 806 |
| 2008 | 0 | 0 | 44 | 643 | 0 | 0 | 0 | 643 | 0 | 0 | 0 | 0 | 643 | 1928 | 1235 |
| 2009 | 0 | 0 | 31 | 442 | 0 | 0 | 0 | 442 | 0 | 0 | 0 | 0 | 442 | 2369 | 1502 |
| 2010 | 0 | 0 | 22 | 269 | 0 | 0 | 25 | 244 | 0 | 0 | 0 | 0 | 244 | 2613 | 1636 |
| 2011 | 0 | 0 | 15 | 187 | 0 | 0 | 0 | 187 | 0 | 0 | 0 | 0 | 187 | 2800 | 1730 |
| 2012 | 0 | 0 | 11 | 131 | 0 | 0 | 0 | 131 | 0 | 0 | 0 | 0 | 131 | 2931 | 1790 |
| 2013 | 0 | 0 | 6 | 72 | 0 | 0 | 0 | 72 | 0 | 0 | 0 | 0 | 72 | 3003 | 1820 |
| 2014 | 0 | 0 | 3 | 41 | 0 | 0 | 0 | 41 | 0 | 0 | 0 | 0 | 41 | 3044 | 1835 |
| 2015 | 0 | 0 | 2 | 26 | 0 | 0 | 45 | -19 | 0 | 0 | 0 | 0 | -19 | 3025 | 1829 |
| Sub. | 0 | 0 | 403 | 5874 | 0 | 0 | 70 | 5804 | 2034 | 744 | 0 | 2778 | 3025 | 3025 | -19 |
| Rem. | 0 | 0 | 0 | 4 | 0 | 0 | 45 | -41 | 0 | 0 | 0 | 0 | -41 | 2984 | 2984 |
| **Tot.** | **0** | **0** | **404** | **5878** | **0** | **0** | **115** | **5763** | **2034** | **744** | **0** | **2778** | **2984** | **2984** | **1816** |
| Disc | 0 | 0 | 302 | 4440 | 0 | 0 | 43 | 4396 | 1889 | 692 | 0 | 2580 | 1816 | 1816 | 1816 |

## RESERVE SUMMARY

| | | Remaining Reserves at April 1, 2004 | | | | | Oil Equivalents | | | Reserve Life Indic. (yr) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Product** | Units | Gross | Working Interest | Roy/NPI Interest | Total Company | Net | BOE Factor | Company Mstb | % of Total | Reserve Life | Life Index | Half Life |
| Residue Gas | Mmcf | 7217 | 2989 | 0 | 2989 | 2673 | 6.000 | 498 | 94 | 12.1 | 10.3 | 2.7 |
| | MMMBtu | 7217 | 2989 | 0 | 2989 | 2673 | | | | 12.1 | 10.3 | 2.7 |
| Condensate | Mstb | 87 | 32 | 0 | 32 | 28 | 1.000 | 32 | 6 | 12.1 | 12.9 | 2.6 |
| Total Oil Eq. | Mstb | 1290 | 530 | 0 | 530 | 474 | | 530 | 100 | 12.1 | 10.4 | 2.7 |

## PRODUCT REVENUE AND EXPENSES

| | | Average First Year Unit Values | | | | | | | Net Revenue After Royalties | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Product** | Units | Base Price | Price Adjust. | Wellhead Price | Net Burdens | Operating Expenses | Other Expenses | Prod'n Revenue | Undisc M$ | % of Total | 10% Disc M$ | % of Total |
| Residue Gas | $/Mcf | 2.95 | -0.94 | 2.01 | 0.21 | 0.01 | 0.00 | 1.79 | 5408 | 84 | 4057 | 84 |
| Condensate | $/Stb | 35.54 | 0.00 | 35.54 | 3.78 | 0.10 | 0.00 | 31.66 | 1007 | 16 | 764 | 16 |
| Total Oil Eq. | $/BOE | 18.56 | -5.37 | 13.19 | 1.40 | 0.04 | 0.00 | 11.75 | 6415 | 100 | 4820 | 100 |

## INTEREST AND NET PRESENT VALUE SUMMARY

| Revenue Interests and Burdens (%) | | |
|---|---|---|
| | Initial | Average |
| Working Interest | 45.0000 | 40.4200 |
| Capital Interest | 86.7647 | 63.4016 |
| Royalty Interest | 0.0000 | 0.0000 |
| Crown Royalty | 10.0000 | 10.0000 |
| Non-crown Royalty | 0.6400 | 0.5494 |
| Mineral Tax | 0.0000 | 0.0000 |
| NPI Payment | 7.5000 | 6.5454 |

| | Net Present Value Before Income Tax | | | | |
|---|---|---|---|---|---|
| Disc. Rate % | Prod'n Revenue M$ | Operating Income M$ | Capital Invest. M$ | **Cash Flow** M$ | $/BOE |
| 0.0 | 5878 | 5763 | 2778 | 2984 | 5.63 |
| 5.0 | 5067 | 4998 | 2675 | 2323 | 4.39 |
| 8.0 | 4673 | 4621 | 2617 | 2004 | 3.78 |
| 10.0 | 4440 | 4396 | 2580 | 1816 | 3.43 |
| 12.0 | 4227 | 4191 | 2545 | 1646 | 3.11 |
| 15.0 | 3942 | 3914 | 2494 | 1420 | 2.68 |
| 20.0 | 3540 | 3522 | 2415 | 1106 | 2.09 |

Project.....1046451
Entity.....Queensland (Total PPP)
Evaluator...Braaten, Keith M.

# APPENDIX

## CERTIFICATES OF QUALIFICATION

Keith M. Braaten, P. Eng.
T. Mark Jobin, P. Eng.
Roger Mahoney, P. Geol.

# CERTIFICATION OF QUALIFICATION

I, Keith M. Braaten, Professional Engineer, 4100, 400 - 3rd Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an employee of Gilbert Laustsen Jung Associates Ltd., which company did prepare a detailed analysis of Australian oil and gas properties of AusAm Resources Limited. The effective date of this evaluation is March 31, 2004.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of AusAm Resources Limited or its affiliated companies.

3. That I attended the University of Saskatchewan and that I graduated with a Bachelor of Science Degree in Mechanical Engineering in 1979; that I am a Registered Professional Engineer in the Province of Alberta; and, that I have in excess of twenty-four years of experience in engineering studies relating to Canadian and International oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of Ausam Resources Limited and the appropriate regulatory authorities.

ORIGINALLY SIGNED BY

Keith M. Braaten, P. Eng.

## CERTIFICATION OF QUALIFICATION

I, T. Mark Jobin, Professional Geologist, 4100, 400 - 3rd Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an employee of Gilbert Laustsen Jung Associates Ltd., which company did prepare a detailed analysis of Australian oil and gas properties of AusAm Resources Limited. The effective date of this evaluation is March 31, 2004.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of AusAm Resources Limited or its affiliated companies.

3. That I attended the University of Calgary and that I graduated in 1984 with a Bachelor of Science Degree in Geology; that I am a Registered Professional Geologist in the Province of Alberta; and, that I have in excess of nineteen years experience in geological studies relating to Western Canadian oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of Ausam Resources Limited and the appropriate regulatory authorities.

ORIGINALLY SIGNED BY

T. Mark Jobin, P. Geol.

# CERTIFICATION OF QUALIFICATION

I, Roger J. Mahoney, Professional Geophysicist, 230 - 38th Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I have been retained by Gilbert Laustsen Jung Associates Ltd., which company did prepare a detailed analysis of Australian oil and gas properties of AusAm Resources Limited. The effective date of this evaluation is March 31, 2004.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of AusAm Resources Limited or its affiliated companies.

3. That I attended the University of Manchester and that I graduated with a Bachelor of Science Degree in Physics with Honours in 1964; that I am a Registered Professional Geophysicist in the Province of Alberta; and, that I have in excess of thirty-seven years experience in geophysical studies relating to Canadian and international oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of Ausam Resources Limited and the appropriate regulatory authorities.

ORIGINALLY SIGNED BY

Roger J. Mahoney, P. Geoph.