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12 June 2001

Mr David Lea
Executive Director
DNRE
Minerals and Petroleum Division
Level 15, 8 Nicholson Street
EAST MELBOURNE VIC 3002

Dear David

VIC/RL5 Patricia Baleen Proposed Development Plan

In May 2001 Diamond Gas Resources Pty Ltd, a 100% owned subsidiary of Mitsubishi Corporation, farmed in to the VIC/RL5 permit taking 40% equity. The remaining equity is split between Cultus (5%) and Basin Oil (55%) both 100% owned affiliates of OMV Australia.

On behalf of the VIC/RL 5 Joint Venture between OMV Australia Pty Ltd and Diamond Gas Resources Pty Ltd, I am pleased to ***enclose*** the Proposed Development Plan for the Patricia-Baleen Field.

This *proposed development plan* (PDP) is submitted as the final contribution in stage two of a two-stage process to obtain approval from the Victorian Government for a production licence for the Patricia-Baleen Gas Field ("Field"), located offshore Victoria, Australia. The decision to designate this project under the Environmental Protection (Impact of Proposals) Act 1974 (the EPIP Act) was taken by the Designated Authority for the Commonwealth - Victoria Offshore Petroleum Adjacent Area in June 2000.

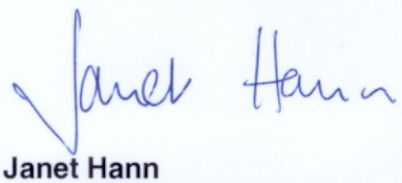
OMV initiated the decision to designate this project when it submitted the "Patricia/Baleen Proposed Development Concept Executive Summary" and the "Preliminary Environmental Advice" to the Victorian department of Natural Resources and Environment in Melbourne in May 2000. In July 2000 OMV submitted a *proposed development concept* (PDC) as the final contribution required in stage one of the two-stage process.

The PDP plan includes the status of commercial arrangements, an overview of the Gas Sales Agreement, an evaluation of geology and reserves, description of the planned development facilities and schedule for the project. The PDP also addresses the comments made by the DNRE on the PDC. Moreover a copy of relevant minutes and various communications between OMV Australia and DNRE and DISR/AGSO are included as an *aide memoir*.

The submission of this *proposed development plan* is made to support the application to the Joint Authority for the granting of a production licence over graticular blocks 1781 and 1782 located in the Victorian Adjacent Area within the Victorian Retention Lease No. 5 (VIC/RL5).

The successful attainment in a timely manner of the necessary Government approvals is critical to the economic viability of this project. Your continued assistance would, therefore, be much appreciated.

Yours sincerely



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PATRICIA BALEEN
PROPOSED DEVELOPMENT PLAN

Prepared by

OMV AUSTRALIA PTY LTD

June 2001

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1.0 SUMMARY

1.1 Background

This proposed development plan (PDP) is submitted as the final contribution in stage two of a two-stage process to obtain approval from the Victorian Government for a production licence for the Patricia-Baleen Gas Field ("Field"), located offshore Victoria, Australia. The decision to designate this project under the Environmental Protection (Impact of Proposals) Act 1974 (the EPIP Act) was taken by the Designated Authority for the Commonwealth – Victoria Offshore Petroleum Adjacent Area in June 2000.

OMV initiated the decision to designate this project when it submitted the "Patricia/Baleen Proposed Development Concept Executive Summary" and the "Preliminary Environmental Advice" to the Victorian department of Natural Resources and Environment in Melbourne in May 2000. In July 2000 OMV submitted a *proposed development concept* (PDC) as the final contribution required in stage one of the two-stage process.

The PDP plan includes the status of commercial arrangements, an overview of the Gas Sales Agreement, an evaluation of geology and reserves, description of the planned development facilities and schedule for the project. The PDP also addresses the comments made by the DNRE on the PDC. These comments were prepared by the DNRE in August 2000 and formally received by OMV in April 2001. However these comments were addressed by OMV in technical discussions with DNRE and DISR/AGSO held in September 2000. A copy of the relevant minutes and various communications are given in Appendix A.

1.2 Subsurface

The main technical updates to the development since the submission of the PDC in July 2000 are the incorporation of 3-D seismic data and the results of the Baleen-2 appraisal well. This has led to a revision of the most likely case reserves from 77 Bscf to 59 Bscf. Two wells are required to drain the field, although the design basis allows for two further wells.

The main reason for the reduction in the reserves is the lowering of the most likely Gross Rock Volume (GRV) by 20% due to the better definition afforded with the 3-D seismic. The combination of the lower volume and a better insight into the areal and vertical distribution of the Gas Initially in Place (GIIP) from 3-D seismic attribute mapping leads to greater confidence in the ultimate number (two) and type (horizontal) of wells required. The Patricia Baleen production life is expected to be around 8 years. Underpinning the work to support these conclusions has been geological modelling of the static reservoir description and simulation of the dynamic flow performance, as well as optimisation for the process design basis consistent with predicted performance. The latter has resulted in selection of a surface facilities configuration with a design capacity of 60 TJ/d.

Sensitivity analysis carried out by varying key subsurface and surface variables confirmed the robustness of the base development plan. The final well location optimisation will be carried out using results from leading edge processing of the 3-D seismic data. These results will form part of the well proposal submissions.

1.3 Development

The development of the Patricia Baleen Gas Field will be initially on a standalone development. It will utilise a new 24km pipeline to export the gas to an onshore plant for processing and compression. This will involve a new shore crossing with the onshore plant located at the nearest landfall (Figure 1.3.1). Two subsea wells will be completed. Offshore facilities will be controlled from the onshore plant. The treated gas will meet the quality specification and entry pressure requirements for the Eastern Gas Pipeline.

Consideration has been given in the development plan to future use of the facilities for transporting and processing third party gas from other nearby fields.

Prequalification of contractors is in progress for tendering both the EPC contract for the onshore works and for the Operations and Maintenance contract. A preferred contractor for the offshore scope was selected as a result of an EPC tender process completed in 2000. Detailed engineering on long lead items (i.e. Xmas trees and controls, umbilicals and pipeline) has progressed.

A Gas Sales Agreement (GSA) was executed with the selected purchaser on 18 May 2001. The GSA is dependent on full board sanction by early July 2001 along with secondary conditions satisfied by 31 October 2001. These include being granted a Production Licence and Pipeline Licences, agreement with the Eastern Gas Pipeline owners for connection and the granting of all environmental approvals.

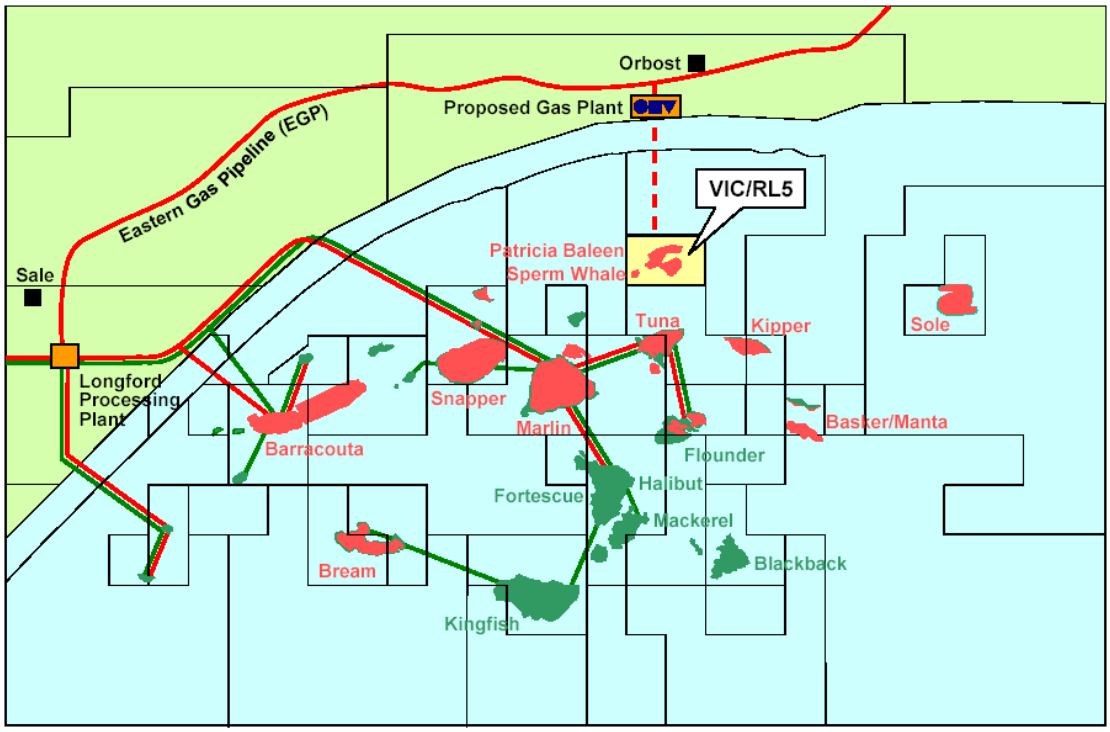

Figure 1.3.1 Patricia-Baleen area map

The project schedule shows a gas delivery date in winter 2002 (Figure 1.3.2).

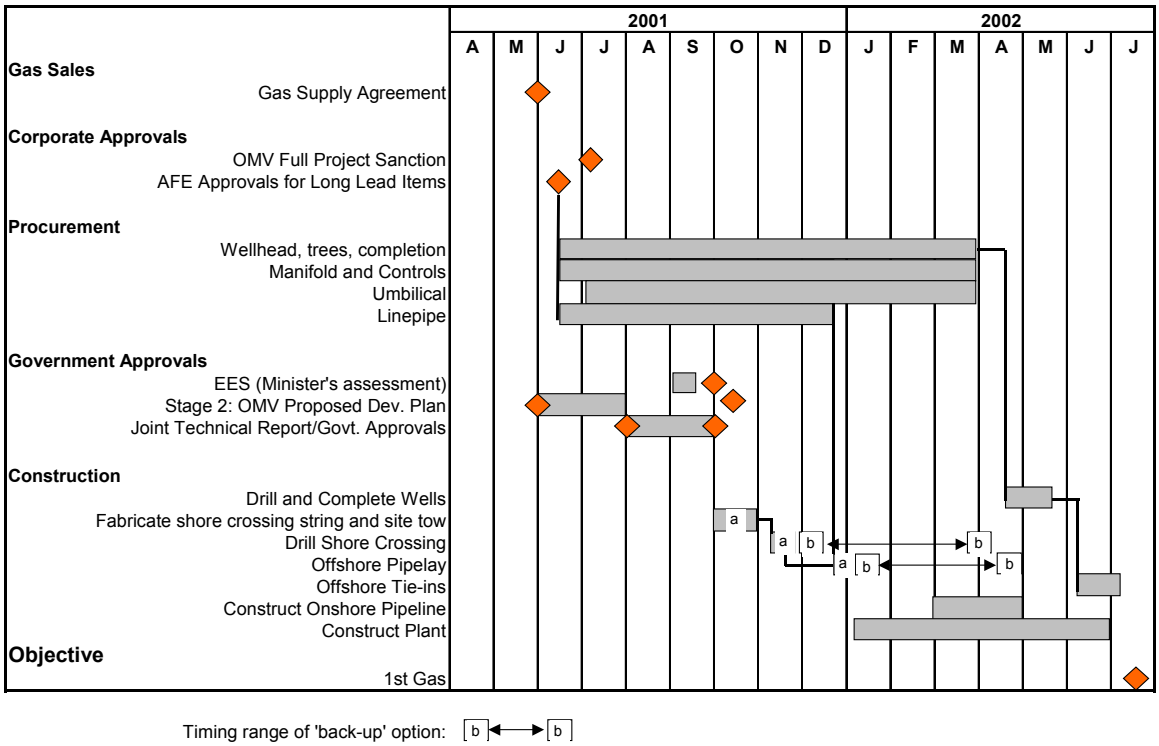

Figure 1.3.2 Patricia-Baleen 1st Gas Schedule

The submission of this *proposed development plan* is made to support the application to the Joint Authority for the granting of a production licence over graticular blocks 1781 and 1782 located in the Victorian Adjacent Area within the Victorian Retention Lease No. 5 (VIC/RL5).

2.0 COMMERCIAL ARRANGEMENTS

2.1 Introduction

This section describes the commercial setting of the project. Important aspects are the Title Permit History, Gas Sales Agreement (GSA) and contracts for the supply, maintenance and operation of the facilities.

2.2 Title

The Patricia Baleen Gas Field is located offshore Gippsland Basin in Retention Lease No. 5 ("VIC/RL5"). The interest is held in a wholly owned subsidiary of OMV, Basin Oil Pty Ltd (ACN 000 628 017).

2.2.1 Permit History

The Patricia Baleen Gas Field is located in the Gippsland Basin, offshore Victoria, Australia, in Permit VIC/RL5 (Figure 1.3.1). The permit containing Patricia Baleen was originally granted to Gas and Fuel Corporation in 1978 as Permit VIC/P11. Interests held at that time were: 33.00% Gas and Fuel Corporation, 29.17% Lasmo (Operator), 4.16% TCPL and 33.00% Beach Petroleum NL. Shell purchased Lasmo's interest in 1989 and Beach/TCPL sold their interests to Gas and Fuel Exploration NL (GFE). Both Lasmo and Shell worked to commercialise the Patricia Baleen discovery during their terms as Operator. Due to a limited gas market, low gas price and lack of infrastructure the project never proceeded. Development studies undertaken showed the potential for a commercial accumulation and in 1993, Shell gained approval from the Victorian government to declare the field as a Location. Shell operated the permit through to 1994 when their interest was transferred to GFE. In 1995 Cultus Petroleum purchased the assets of GFE and acquired a 100% interest in the Patricia Baleen Gas Field as a result. Based on further study work undertaken by Cultus, a retention lease was granted to Cultus over the field on 14 November 1996. In 1999 OMV gained full control of Cultus Petroleum and acquired a 100% interest in the Patricia Baleen Gas Field. In May 2001 Diamond Gas Resources Pty Ltd, a 100% owned subsidiary of Mitsubishi Corporation, farmed in to the VIC/RL5 permit taking 40% equity. The remaining equity is split between Cultus (5%) and Basin Oil (55%) both 100% owned affiliates of OMV Australia.

2.3 Gas Sales Agreement

A tender exercise for the purchase of 80PJ of Patricia-Baleen gas was carried out in mid 2000. The tender exercise did not fulfil OMV's minimum requirements on gas price and conditions. The tender exercise was terminated.

A re-evaluation of the Gas Initially in Place (GIIP) and reserves as a result of the incorporation of the 3-D seismic data and the Baleen-2 appraisal well information resulted in a downward revision of the available sales gas volume to 59PJ.

A revised marketing strategy in late 2000 early 2001 resulted in OMV selecting a preferred purchaser with agreement achieved on the commercial terms and conditions mid April 2001, for the sale of Patricia Baleen gas. A GSA was executed between Basin and a selected purchaser on 18 May.

Key considerations of the GSA for a sole purchaser include:

- Agreement to purchase a minimum of 59PJ of gas over an eight year period, in a depletion-type contract in accord with the OMV preferred production profile.
- Under the Contract Basin agrees to sell and deliver and Buyer agrees to purchase and take from Basin and pay for gas ("take or pay").
- The GSA provides for Basin and Buyer to have full board sanction by 6 July 2001 and all Secondary Conditions satisfied by 31 October 2001. Secondary Conditions include but not limited to Basin being granted a Production Licence and Pipeline Licences, achievement with the Eastern Gas Pipeline owners for connection and the granting of all environmental approvals. Buyer's approvals relate to matters of transport, injection and delivery of gas into the Principal Transmission System.
- A Contract Price in Australian Dollars per Gigajoule (A$/GJ) Real Term 1/7/2001 for Patricia-Baleen gas delivered at the entrance to the EGP at Orbost. This price to be partially or fully escalated annually at CPI from 1/1/2002.
- The nominal start date for gas sales will be 1 July 2002.

2.4 Contracts for Facilities

Offshore Facilities

The scope of work for the offshore facilities includes the detailed engineering, procurement, fabrication, installation, hook up and commissioning scopes of work. The scope of work has been determined during FEE (frontend engineering), and includes all facilities required to construct, produce and transport gas delivered to the onshore plant.

Detailed engineering has progressed as far as possible prior to the appointment of a construction contractor and detailed definition of work methods.

It is possible to separate the offshore construction scope into two parts, namely pipelay and tie-ins. This will provide an opportunity to make use of a large pipelay barge which will be in the area for other projects in late 2001 / early 2002, while still allowing flexibility to complete the tie in work with other smaller vessels after drilling and completion of the production wells. This is expected to be in execution at the end of the first quarter of 2002.

OMV will specify and procure all major materials, such as the Xmas Trees and subsea control systems, the linepipe and the subsea umbilical.

Onshore Facilities

Prequalification of contractors is in progress for tendering both for the Engineering, Procurement and Construction (EPC) contract for the onshore works and separately for the Operations and Maintenance contract.

An EPC contract shall be awarded for the design, procurement and construction of the plant and transmission pipeline.

It is intended to let a service contract for the supply of operating and maintenance services with an operations contractor that is recognised has having a track record in the operations and maintenance of both onshore and offshore hydrocarbon facilities.

3.0 SUBSURFACE DEVELOPMENT

3.1 Geophysics

3.1.1 Seismic Data

The geophysical database is comprised of multi-vintage 2D and a recently acquired 3D seismic survey. Enclosure 3.1.1 outlines both the 3D survey and the existing 2D seismic database. The main 2D surveys utilised in the previous 1999 mapping were the GB79, GB81 and GL88 surveys, which were acquired in 1979, 1981 and 1988 respectively. The combined 2D surveys result in a line spacing of 500 m over the Baleen, Patricia and Sperm Whale features. The 2D dataset was reprocessed in 1991 by Shell Development Australia and this dataset was used for the 2D mapping.

In 1Q 2000, a 3D seismic survey was shot over the Patricia-Baleen area. The 3D acquisition area measures 84 full fold sq km and consisted of shooting parallel lines with 3 streamers spaced 12.5 m apart with each line having a 12.5 m receiver group spacing and a shot interval of 25m per CMP line. This resulted in a subsurface bin size of 6.25m x 12.5m.

3 1.2 3D Processing

A phase controlled Pre Stack Time Migration (PreSTM) and Preserved Amplitude processing sequence was employed in order to optimise the subsequent seismic inversion. Emphasis was put on a detailed stacking velocity analysis and preserving as many far offset traces as possible. The result of a very extensive processing sequence was a preserved amplitude high resolution dataset with a center frequency of 50Hz within the reservoir zone.

Both a full offset cube and 3 angle of incidence dependent cubes (near, mid and far offsets) were generated and subsequently inverted to acoustic impedance (AI) and elastic impedance (EI) cubes respectively. The Baleen-2 well (VSP) and shear wave sonic were used to calibrate the inversion process. Figure 3.1.2 shows the excellent VSP to seismic tie at Baleen-2.

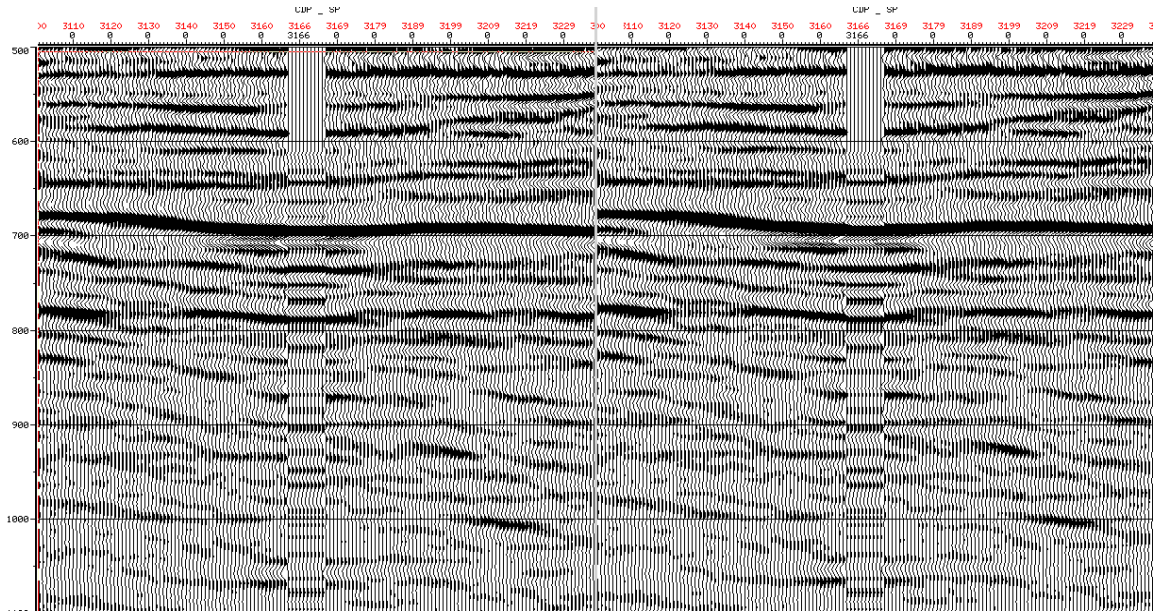

Figure 3.1.2: Baleen-2 Corridor stack, right with inverse dispersion Q (180) filter

The EI processing was necessary because of the strong AVO effect caused by the presence of gas within the Gurnard reservoir. Moreover the inversion process eliminated most of the strong tuning effects and increased vertical seismic resolution to 4-6m. It is anticipated that crossplotting

techniques of different cubes will enable the differentiation of amplitude effects related to gas pay and lithology changes, respectively.

3 1.3 3D Seismic Interpretation

The high resolution 3D resulted in a more accurate definition of the structural configuration and the lateral extent of the gas pay zones. Figure 3.1.3 is a 3D visualisation of the 3D seismic cube uncovered at top Gurnard reservoir level. Red amplitudes are related to high negative values and are caused by a significant drop in AI at top Gurnard reservoir level due to the presence of gas.

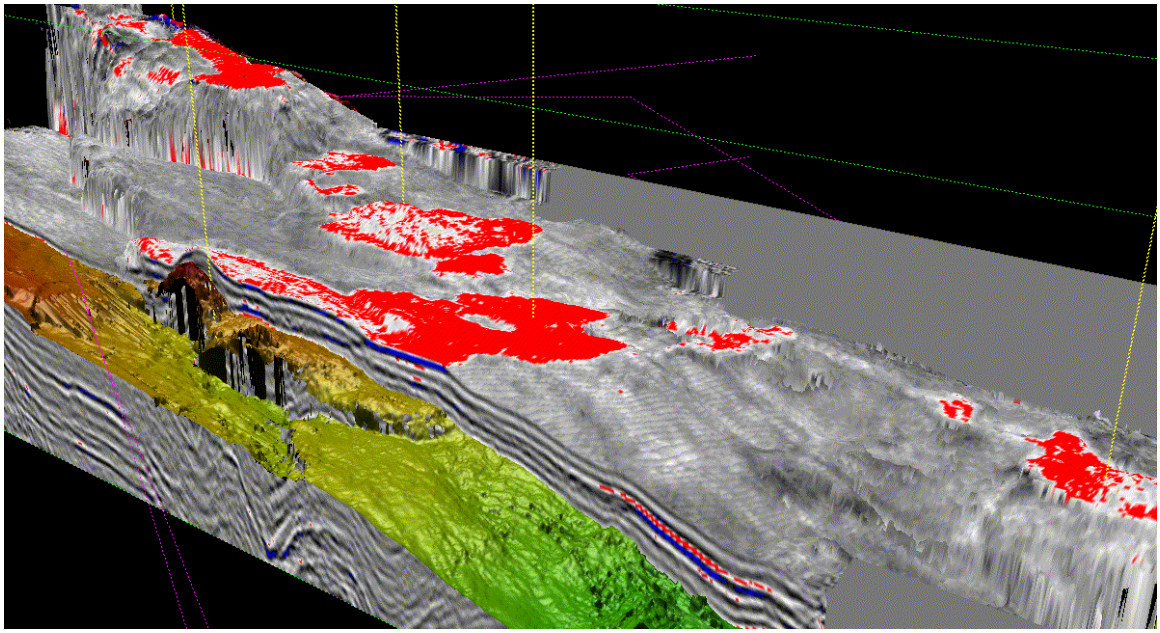

Figure 3.1.3 3D visualisation of the 3D seismic cube uncovered at top Gurnard reservoir level

The following horizons were picked and auto-tracked:

- Seabottom for depth conversion
- Top high velocity carbonates for depth conversion
- Top Gurnard gas reservoir (The seismic pick is not identical to the top of the Gurnard formation but to the top of the first good quality sand. The vertical difference is in the order of 4 to 6m)
- Top Latrobe Coarse Clastics (LCC) or Base Gurnard reservoir
- Top Strzelcki Unconformity
- Gas Water Contact (GWC) within Gurnard (free water level)
- Gas Down To (GDT) within Gurnard. (This grid is a merge between the “free” GWC and the Top Siderite band grid and is the bottom limitation of the Gurnard gas column)

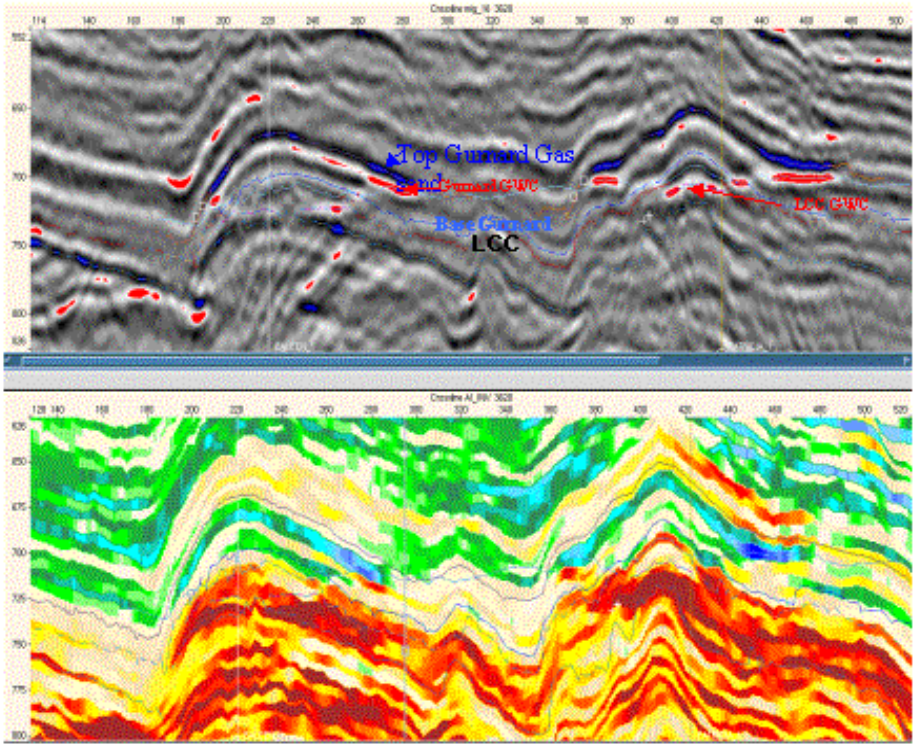

Figure 3.1.3a A 3D NW – SE crossline through the Patricia and Baleen accumulations

Two Way Time (TWT) Seismic and 3D AI Inversion section through Patricia-1, Baleen-1 is projected in from a NE direction. A dark blue/black event on seismic is a decrease in AI, a white/red event on seismic is an increase in AI (e.g. AI), low AI values (e.g. gas sands) are displayed in bluish and greenish colours on the AI display.

The following important observations were made:

- The seismic has excellent vertical resolution down to 7-10m at reservoir level. The 3D inversion increases vertical resolution up to 4m.
- It is possible to pick the GWC, a situation rarely available in seismic interpretation exercises. This provides an alternative and independent methodology to the conventional method of depth converting top reservoir and using the spill point or lowest closing contour for GRV estimation. Figure 3.1.3a is a 3D NW – SE crossline through the Patricia and Baleen accumulations. Both the conventional seismic and the 3D full stack inversion section are displayed. One can clearly identify top and base gas both in the Gurnard and the LCC section. The inversion demonstrates the layered nature of the Gurnard reservoir.
- It is possible to seismically distinguish between the Gurnard GWC and the LCC GWC.
- The top reservoir pick within the gas leg is very robust because of a significant drop in acoustic impedance due to gas. Outside the gas leg the confidence is much lower since the water wet Gurnard is acoustically very similar to the seal rocks. Sometimes (but not always) the polarity switches form peak (gas leg) to trough (water leg). Attribute maps permit differentiation between areas of a free GWC and gas on rock regions, respectively.

3.1 4 Depth Conversion, GWC from Seismic

The depth conversion used a layer cake methodology based on stacking velocities and gridded correction functions at the well locations. On average the stacking velocities had to be reduced by 8% to fit the well depths. This is very reasonable since the DIX equation wrongly assumes that RMS velocities are identical to stacking velocities. This assumption is true only for relatively small

offsets and angles of incidence, a condition not met for shallow events such as the Gurnard. Enclosure 3.1.2 is a Top Gurnard gas reservoir depth contour map with an RMS amplitude colour overlay. Enclosure 3.1.3 is a depth map derived by simply converting stacking velocities to average velocities from seismic datum to Top Reservoir and using them for depth conversion. The similarity between the two depth maps gives encouragement that the detailed 3D stacking velocity picking (400 x 400m for PSTM NMO) has captured shallow velocity anomalies within the Miocene channel sequences well enough to rely on seismic velocities for depth conversion.

Moreover the following significant observations can be made from depth and amplitude maps:

- The depth structure maps and the associated fault pattern clearly show that the Baleen accumulation must be subdivided into three features with individual crests.
- In the immediate vicinity north of Baleen-2, en echelon faults drop the Gurnard reservoir beneath the GWC. The en echelon nature suggests lateral movement along faults. Therefore even faults with minor vertical throw might act as zones of somewhat lower transmissibility.
- Gas amplitudes are coincident with the 735m TVDSS depth contour at Baleen. This indicates that Baleen is very likely full to spill and supports a field wide contact (or GDT) of 738m TVDSS as found in the Baleen-2 well. It should however be noted that because of tuning effects the amplitude anomaly starts to dim at a column height of 4 to 8 m. Therefore the amplitude shut off is not perfectly coincident with the lowest closing contour. Because of vertical resolution issues the accuracy within which the contact can be determined seismically is in the order of +/- 4m.
- The lowest closing contour (LCC) at Patricia coincident with the gas amplitude outline is at 730m TVDSS for most of the Patricia accumulation. There is however a significant exception at the eastern edge of Patricia where the LCC seems to be between 705m and 700m TVDSS. Possible explanations are a stratigraphic pinchout, a lithology change, a Top Gurnard pick which is too high in the water leg or a local velocity anomaly not captured by the stacking velocity analysis. A 2D PreSDM subsequently carried out on sail line 440 (200m south of Patricia-1) confirmed the GWC to be at 730m TVDSS. The most likely explanation of the mismatch of amplitudes and lowest closing contour in the eastern part of Patricia is therefore a local velocity anomaly combined with a seismic pick which is one half cycle too high within the Gurnard water leg. For practical purposes the contours were subsequently manually edited to provide an input map for the reservoir simulation with a LCC at 738m. The reservoir simulation was run with a GWC contact at 730m TVDSS.

3.1.5 Gross Rock Volume (GRV) Estimation

Two independent methods were used to derive the combined Gurnard - GRV of Baleen top, mid. and bottom, Patricia and Patricia-East (Figure 3.1.5). Table 3.1.5 summarises the results of the different GRV estimations and defines the different accumulations. Latrobe Coarse Clastics volumes were not included in the volumetrics.

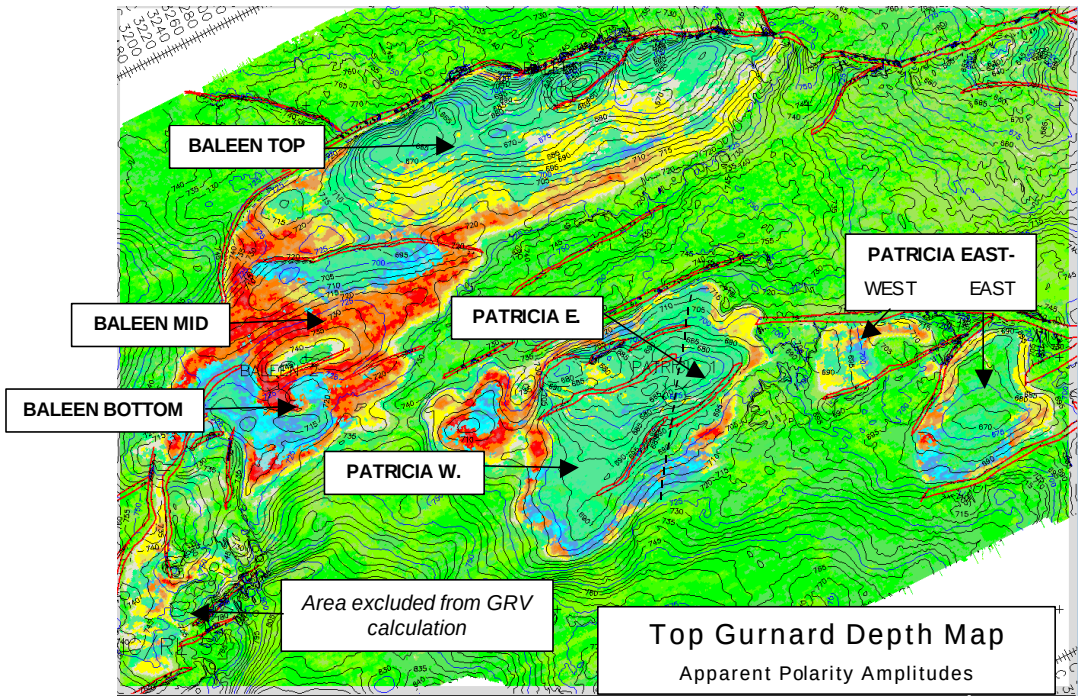

Figure 3.1.5. Top gurnard depth map

ACCUMULATION	Vint from well data Vint interpolated	GRV [sqkm*m] GWC picked on seismic	GRV [sqkm*m] GWC = 738m	GRV [sqkm*m] GWC = 734m
BALEEN TOP	2069	120.93	129.45	119.19
BALEEN MID	2140	27.23	33.19	25.40
BALEEN BOTTOM	2193	28.89	24.20	17.42
BALEEN TOTAL		**177.06**	**186.84**	**162.00**
PATRICIA WEST, GWC=const		N/A	81.30	71.38
PATRICIA EAST, GWC=const	2020	N/A	20.99	15.76
PATRICIA TOTAL	**2120**	**81.97**	**102.29**	**87.14**
PATRICIA EAST - W	2050	4.55	3.37	1.04
PATRICIA EAST - E	2050	15.49	23.36	16.52
PATRICIA EAST TOTAL		**20.04**	**26.73**	**17.56**
BP TOTAL		**279.07**	**315.85**	**266.69**

Table 3.1.5 GRV's from both conventional depth conversion and from depth converted isochrones (GWC picked on seismic)

1. The Top reservoir pick, the GWC pick and the base reservoir pick (LCC) were used to generate a gross pay isochron map. This map was then depth converted by using a range of constant interval velocities as derived from well check shot data. The method is insensitive to any overburden velocity anomalies since all 3 events would be affected in a similar way. Since both Top reservoir and GWC are excellent seismic events this method is very robust. The major sensitivity of this method is the average constant interval velocity used for depth conversion.
2. The second method used the conventional approach of depth-converted grids (Top Gurnard reservoir, Top LCC) and a constant GWC of 738m (or 734mTVDSS) for all accumulations, respectively. Gas on rock areas were accounted for. Enclosure 3.1.4 is a Gurnard isopach map. It should be noted that this map does not include the siderite band between Base Gurnard and Top LCC.

The similarity of the Baleen GRV's derived through different methods increases the confidence that the Baleen accumulation has a GWC of 738m TVDSS. On the contrary, the Patricia accumulation

method 2 resulted in higher GRV's for both the 738m and 734m GWC scenario than method1, which derived the GRV through a seismic pick of the GWC or GDT area. This observation supports the hypothesis of a Patricia GWC contact at 730m TVDSS but Patricia.

The two accumulations of Patricia-East do not have sufficient volumes to consider their development currently.

3.1.6 Future Inversion Work

Elastic impedance and amplitude impedance inversion work will be carried out to highlight areas of better reservoir quality and connectivity in a much more detailed fashion than the conventional 3D seismic. The objective of this work will be to better define the internal reservoir architecture and build a detailed geological model to optimise the final development well locations and well trajectories. The model will also form the operational basis for reservoir management purposes. This modelling will be ongoing through the execution phase of the project.

3.2 Regional Geology

3.2.1 Depositional and Structural History

The Gippsland Basin is an asymmetric East-West graben which initially formed during the break-up of Australia and Antarctica in the Early Cretaceous. During continental rifting the basin was filled by non-marine clastics of the Strezlecki Group, in part volcanolithic and containing coal beds (Figure 3.2.1). The Strezlecki Group may be sub–divided into two megasequences separated by an Aptian age unconformity (Gippsland, A Composite Basin – A Case Study from the Offshore Northern Strezlecki Terrace, Gippsland Basin, APPEA Journal 1994, Michael B. Gilbert & Kathy A. Hill 1994). The lower megasequence comprises Berriasian to Late Aptian aged sediments in an actively subsiding, syndepositional growth fault controlled setting. The upper megasequence appears to have accumulated as a result of regional down warping and little extensional activity. The upper megasequence is far more uniform in thickness and ranges in age from Albian to earliest Cenomanian.

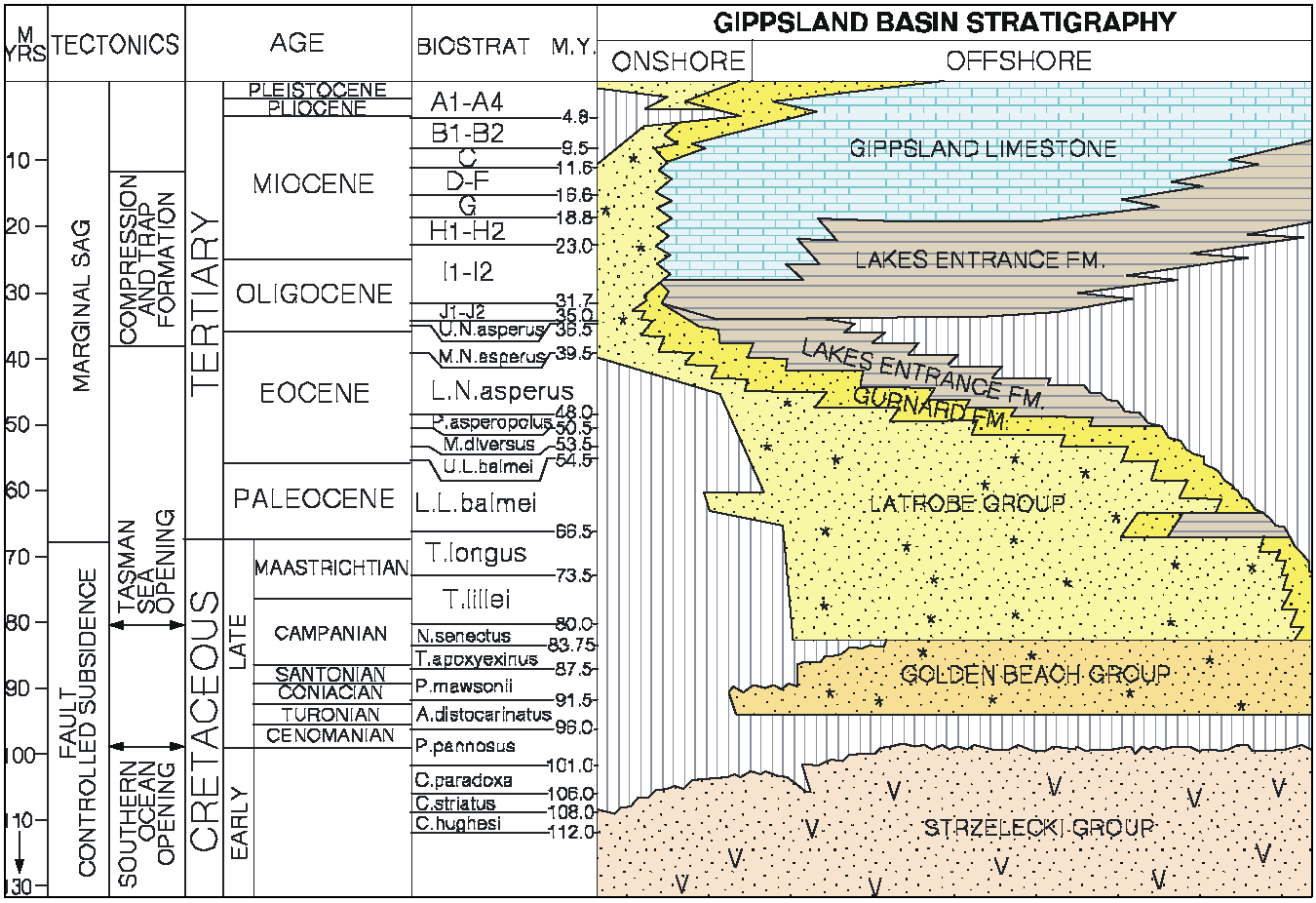

Figure 3.2.1 Gippsland Basin Stratigraphy

The overlying alluvial sediments of the late Cretaceous Golden Beach Group represent a second phase of rift fill associated with the Tasman Sea rift. Following continental break-up in the Campanian, the Latrobe Group was deposited as a transgressive sequence of marine and coastal plain sediments. The deposition of marine marls and limestones of the Lakes Entrance Formation and Gippsland Limestone accompanied thermal subsidence from the Oligocene to Recent.

The thickest deposition of the Latrobe Group and Golden Beach Group was in the “Central Deep” between the Rosedale and Foster faults, collectively exceeding 5km (Figure 3.2.2a). North of the Emperor Fault the Latrobe Group is generally less than 500 metres in thickness and overlies the Strezlecki Group unconformably. It is developed in a marginal marine “coarse clastic” facies. The

Patricia-Baleen gas field lies within this Northern Platform / Northern Terrace area (Figure 3.2.2b). The Latrobe Group is observed to gradually thin and pinch out to the north of Baleen-1.

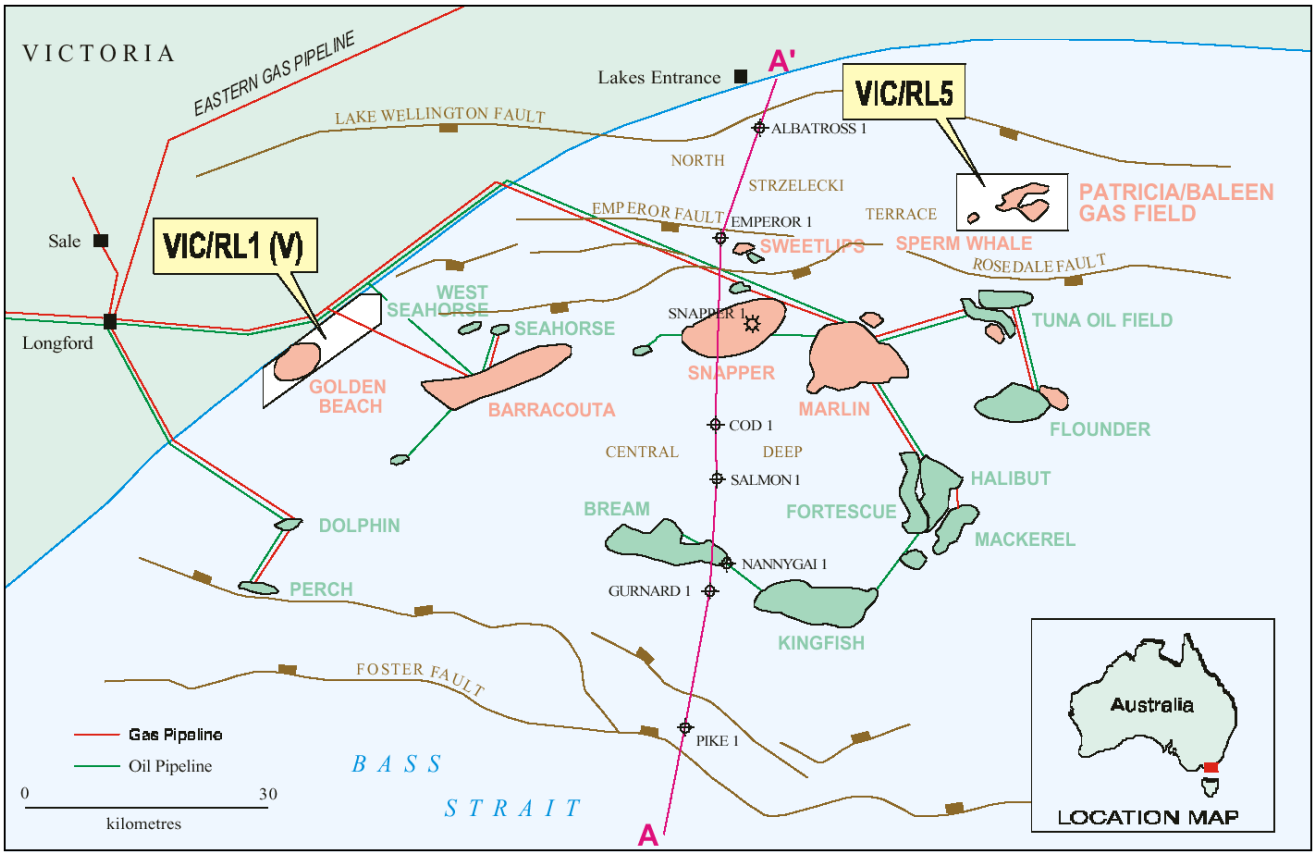

Figure 3.2.2a Gippsland location map

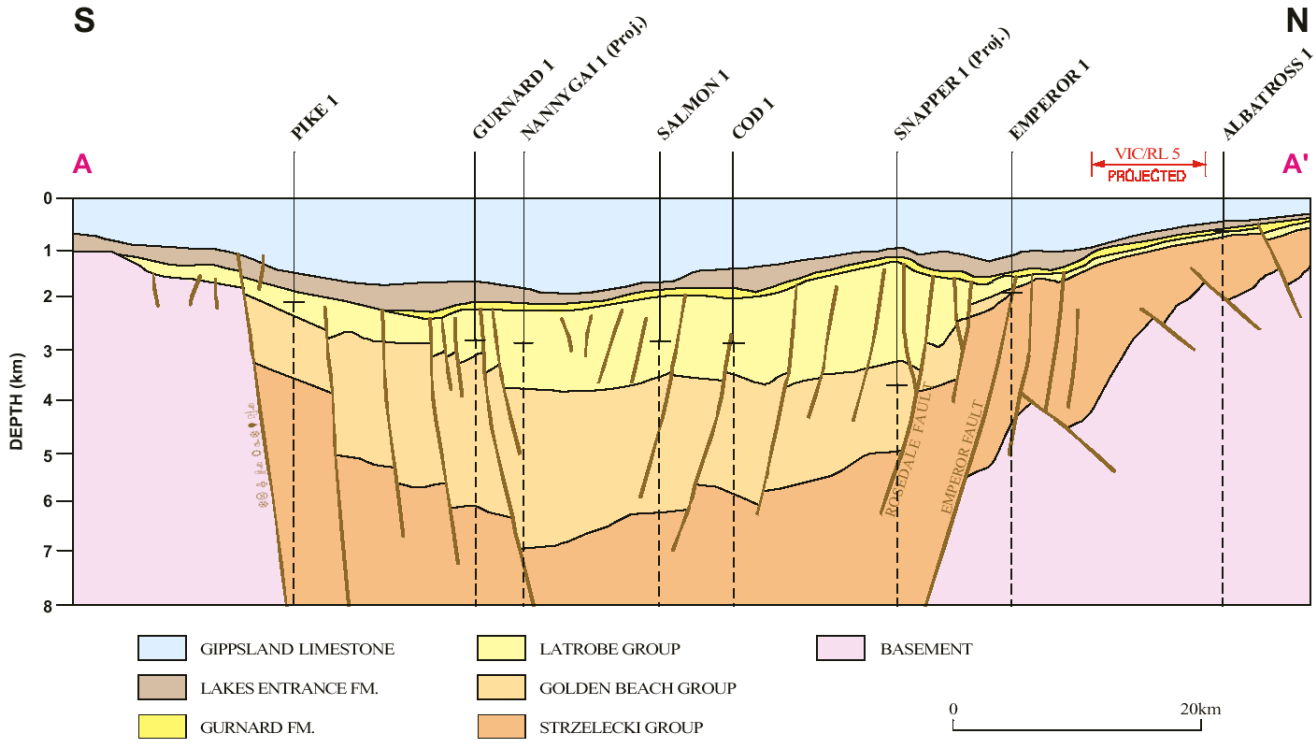

Figure 3.2.2b Gippsland cross section

Marine inundation of the Latrobe Group coarse clastics in the Middle Eocene, coupled with low subsidence and sediment input rates, resulted in deposition of a condensed, glauconitic, sandy siltstone known as the Gurnard Formation. This formation is widespread but discontinuous, and is overlain by the Oligocene Lakes Entrance Formation.

While extensional rifting and thermal subsidence have dominated the depositional history of the Gippsland Basin a dextral east-west wrench regime has been active intermittently from the late Paleocene to the Pleistocene, with the most intense effects evident in the Middle Miocene. This has resulted in anticlinal structuring on generally northeast – southwest axes, and the re-activation of many normal faults as reverse or wrench faults.

3.2.2 Hydrocarbon Generation and Entrapment

The Gippsland Basin is a major oil and gas province and over the last 35 years the factors relating to this have been well researched.

Source

Potential source rocks exist in the Strezlecki, Golden Beach and Latrobe Groups. Limited work on the Golden Beach suggests its potential is mainly for gas and condensate, while the Strezlecki is considered to be a gas source. By far the richest organic content is found in the Latrobe Group, particularly the upper part.

On the margins of the basin the Latrobe Group is immature for oil generation but the Golden Beach (lowermost Latrobe Figure 3.2.1) is likely to be mature for gas on the Rosedale-Emperor terrace and the Strezlecki will be in the oil and gas windows to the north of this.

Reservoir

The marginal marine and coastal plain transgressive sequence of the Latrobe Group contains the main reservoirs of the Gippsland Basin.

The top Latrobe Group “coarse clastics”, comprising coastal barrier and braided stream deposits, is present over the whole basin and contains the main regional aquifer. These sands are the reservoir for 95% of Gippsland oil and over 80% of the gas and generally have very good porosities and permeabilities. Intra-Latrobe reservoirs, sands of upper or lower-coastal plain faces, account for most of the remaining oil.

The alluvial fan sediments of the Golden Beach Group account for some 15% of the gas reservoirs encountered to date. Their quality as oil reservoirs is fairly poor.

The Gurnard Formation, sporadically developed over the top Latrobe, is a reservoir of variable quality, grading to a seal. In the Patricia-Baleen gas field most of the Gurnard Formation exhibits good reservoir characteristics having very good porosity and moderate permeability. The Gurnard Formation contains the major part of the Patricia-Baleen gas accumulation, with only about 5% in the underlying top Latrobe Group sandstones.

Seal

The regional seal for the whole offshore basin is the Oligocene Lakes Entrance Formation, of marine marls grading upwards into fine-grained biogenic carbonates and oozes. This highly effective seal ensures that any valid structural high on top Latrobe or Gurnard level, in the path of oil or gas migration and not subsequently breached, will contain hydrocarbons.

Intraformational seals are present within the Latrobe Group. None are regional, and their effectiveness depends on structuring.

The Patricia-Baleen gas field is sealed at Lakes Entrance Formation level.

Hydrocarbon Trapping

In the deepest part of the Gippsland Basin, oil generation from the lower Latrobe Group would have occurred prior to the deposition of the Lakes Entrance Formation, and most of that oil has been lost. Following the deposition of an effective seal, oil accumulated in highs bounding the kitchen area, predominantly at top Latrobe level.

Oil remigrated from some of these Oligocene traps or became redistributed within them during the anticlinal flexing of the Middle Miocene. Remigration also occurred as sources moved into the gas window and oil was displaced from structures in the gas migration path. Oil in shallow onshore accumulations such as those at Woodside and Lakes Entrance establishes the fact that hydrocarbons have, at top Latrobe level, migrated to the basin margins.

The Patricia-Baleen gas has been emplaced either by migration from the Central Deep or by local generation in the Strezlecki Formation.

3.2.3 Reservoir Stratigraphy

The Patricia-Baleen gas reservoir is predominantly in the very fine silty sandstones of the Gurnard Formation. Some gas is present in the Latrobe Group Coarse Clastics immediately below the Gurnard Formation but comprises only about 5% of the total GIIP. The Latrobe Group Coarse Clastics have some low H_2S concentrations recorded on drill stem testing reports, and given the very small volumes this gas is not believed economically viable within this development plan.

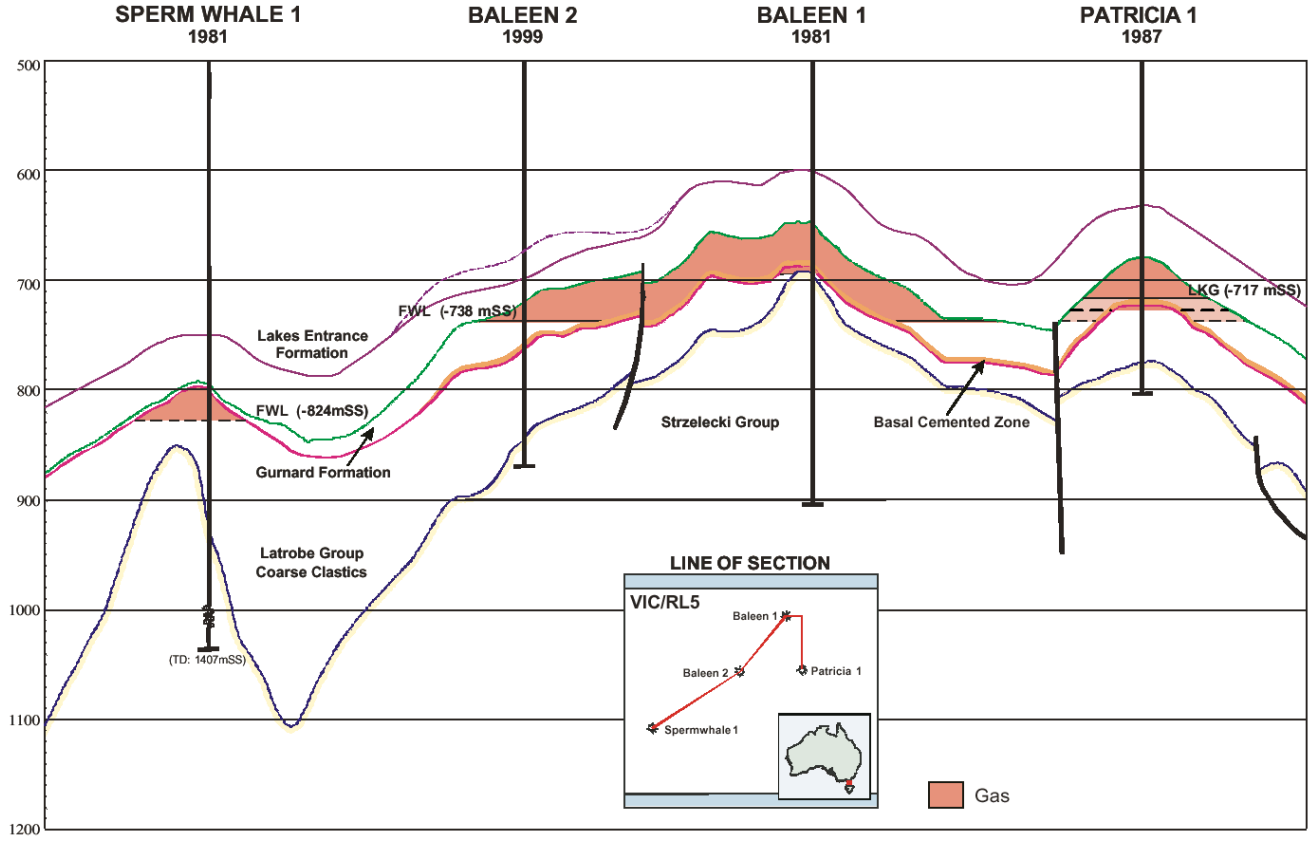

Figure 3.2.3 Patricia-Baleen cross section

3.2.4 Lithology

As noted previously, the Gurnard Formation represents the last of the Latrobe Group sedimentation or, as considered by some, the onset of the Seaspray Group deposition. It consists of very fine micaceous, glauconitic and sideritic sands and silts with moderately high clay content. The clays are dominantly illite smectite mixed layer types. Multiple siderite/limonite bands are present throughout the reservoir at Patricia-1 and Baleen-1 and Baleen-2. These bands of siderite cementation can be confidently correlated. (Enclosure 3.2.1)

3.2.5 Depositional Environment

The entire reservoir is bioturbated with almost all the original deposition features disrupted by common Thalassinoides and Ophiomorpha with lesser Skolithos and Zoophycos. Interpretation of the core and logs at Patricia-1 and Baleen-2 confirms the Gurnard Formation as the last of clastic terrigenous deposition prior to flooding and the more open marine depositional sequences of the Sea Spray Group. The completely bioturbated fabric suggests a depth of water below wave base with storm induced turbidite or suspension deposition as the main mechanisms of sediment transport to the field area. Overall environment is interpreted as offshore marine to distal transitional lower shoreface.

The presence of the siderite bands is indicative of reducing environments syndepositionally or shortly thereafter. The lateral extent of the bands is evident from well correlations. There may have been several minor transgressive, regressive events during Gurnard Formation time creating the multiple sideritic bands through a combination of sediment starvation and changing redox conditions in the upper few metres of sediment. This is significant in that while individual sands appear to be fairly isotropic (given the bioturbation), the bands are interpreted as moderately effective barriers to vertical movement of fluids.

3.2.6 Geological Reservoir Model

The conceptual model for the Gurnard Formation reservoir at Patricia Baleen comprises a section approximately 20m to 45m in thickness bounded above by the sealing calcareaous claystones of the Lakes Entrance Formation and below by a dense, cemented zone immediately overlying the Latrobe Group Coarse Clastics. This upper surface of the Gurnard Formation is described by the Top Gurnard Formation Depth Map (Figure 3.1.5) The depth conversion is described in the section on geophysical mapping (Section 3.1.4).

The gross reservoir thickness maps show good reservoir thickness in the Baleen-2/SW Baleen area. These maps are based on well intersections and thicknesses from seismic data. The older high features around Baleen-1, Spermwhale-1 and towards Flathead-1 show marked thinning of the unit onto these positive features. Sperm Whale-1 encountered only 6m of Gurnard Formation and this was non-reservoir, the presence of the formation being interpreted on the basis of palynological dating. Areas of thicker section are observed over the Patricia feature and on the flanks of the Baleen culmination, particularly to the south-west.

The multiple siderite/limonite bands through the reservoir strongly suggest movement of fluids will be laterally along the intervening higher porosity sand packages rather than vertically through the reservoir. This, coupled with the basal cemented zone which demonstrates a partial pressure seal against the Latrobe Group Coarse Clastics at Patricia-1 and Baleen-2 means bottom water drive is likely to be negligible. The multiple siderite bands delineate the flow units of the reservoir. Correlation of these between the three field wells, Baleen-1, Baleen-2 and Patricia-1, is shown in Enclosure 3.2.1 and forms the basis for the layering used by the Eclipse Reservoir model. Relative to the previous geological model the Baleen-2 well showed an increase in gross and net reservoir in the SW extension of the Baleen structure. Moreover there is a decrease in both the number and thickness of the siderite cemented bands in the well correlation. Seismic interpretation has also

shown the basal cemented zone may be absent on the crest of the Baleen high. The Baleen-1 well shows a 7m thick Latrobe Group Coarse Clastics veneer above the Cretaceous Strezlecki Group economic basement.

At Baleen-2, the siderite cemented bands are not so easily correlated to the other wells and form a densely cemented zone in mid reservoir, however, at least 8 discrete bands do occur outside the main cemented zone at Baleen-2. The correlation (Enclosure 3.2.1) is based on raw wireline log characteristics and values. A correlation based on spectral gamma ray data from the Patricia-1 and Baleen-2 wells support the basic log correlation.

A minimum of four parasequences are recognised in the core from Baleen-2. Baleen-2 routine core and special core analysis support three main rock types to define the reservoir rock (see section 4.2.3).

Some aquifer support in the form of edge water will be present, however, the relative mobilities of the gas and water in this moderately permeable reservoir will mean gas expansion and depletion is the main reservoir drive. The position of the field on the Northern Strezlecki Terrace, and the north bounding faults to the culminations further restrict aquifer access to the gas accumulations. Patricia is modelled as open to the aquifer on the west, south and east flanks while Baleen is open to the west and south-west.

3.3 Formation Parameters

3.3.1 Overview

Several petrophysical studies on the wells have been carried out over the years (Petrolab 1982, GFE 1985, Lasmo 1987, Shell 1992, University of New South Wales 1997, Schlumberger 2000). The evaluation models used and the different approaches have resulted in a range of values for the key reservoir properties.

The petrophysical analysis carried out by Schlumberger in July 2000 was used in this current estimate of the gas in place volumes and reserves for the Patricia-Baleen field.

The petrophysical analysis covers three wells (Patricia-1, Baleen-1 and Baleen-2) in a consistent manner using the same deterministic model. The Baleen-2 well was also evaluated using a more complex model as the more extensive data set allowed this.

Pressure data has been used to determine the FWL, provide insights into formation depletion due to main Bass Straits field production and identify pressure discontinuities (Appendix C).

Complex mineralogy of the Gurnard Formation reservoir at Patricia Baleen, severely limits the effectiveness of the available wireline logs in characterising and quantifying the reservoir. Derivation of a suitable Vclay indicator in the reservoir has been a difficult problem to solve. Routine and Special core studies along with petrographic studies from Patricia-1 and the recent appraisal well, Baleen-2 have now been incorporated into this proposed Development Plan.

3.3.2 Data Availability

Log coverage in the wells is good (Table 3.3.1).

The quality of the log data is in general good with the exception of the sonic logs. The sonic log quality over the reservoir section of the Gurnard formation in both Baleen-1 and Patricia-1 is poor due to the considerable amount of cycle skipping associated with gas zones. The Baleen-2 well was logged with the Dipole Sonic tool and the data quality is good although affected by the high porosity gas zone in the upper half of the reservoir.

The core in Patricia-1 and Baleen-2 covers most of the Gurnard Formation intersected in the wells. There is limited SCAL data available from Patricia but a reasonably extensive SCAL set from Baleen-2.

	Baleen-1	Baleen-2	Patricia-1
Wireline Logs	DLL-MSFL-GR FDC-CNL-GR BHC-GR RFT-GR HDT-GR CST	PEX-HALS-DSI-NGS FMI-GR MDT	DLL-MSFL-GR LDL-CNL-GR SLS-NGT RFT-HP-GR CST
Core	Nil	31.62m (94%) core recovered	39.8m (97%) core recovered
RCAL	N/A	90 plugs analysed	107 plugs analysed
SCAL	N/A	18 plugs analysed	3 plugs analysed
SWC	18 recovered	NIL	8 recovered
Petrology/ Petrography	3 samples (SWC)	12 samples analysed (core plug off cuts)	9 samples

Table 3.3.1 Patricia-Baleen Well Data Coverage

3.3.3 Petrophysical Analyses

Schlumberger carried out a petrophysical analysis of the three wells (Patricia-1, Baleen-1 and Baleen-2) using their ElanPlus probabilistic software.

The field analysis was complicated by the complexity of the mineralogy, and the differences in the number, type and vintage of the logs in the wells. The analysis resulted in

- Siderite bands being identified from log character with suitable formation parameters estimated for the siderite bands.
- A common Elan-simple 'lumped' model created for all three wells (Table 3.3.1, Figures 3.3.1, 3.3.2, 3.3.3a and 3.3.3b) and
- A more 'complex' Elan model created for Baleen-2 (Figure 3.3.3b) only, giving greater confidence to its results (Table 3.3.1).

In Baleen-2, the 'lumped' model is based on fewer logs and of lower resolution than the 'complex' model. A measure of the uncertainty in the 'lumped' model versus the 'complex' model is obtained from Baleen-2. This is incorporated in the uncertainty ranges for the 'lumped' model based Patricia-1 and Baleen-1 analysis.

Calibration of the Elan models was carried out against the core porosity and grain density measurements for Patricia-1 and Baleen-2. In general the resistivity curves did not lend themselves to true estimates of water saturation in the wells due to the presence of pyrite, even with the Elan analysis. Hence, capillary pressure data for varying rock type was used in the reservoir model for gas saturation estimates (Section 4).

The methodology used to determine the geological unit (layer) average petrophysical parameters (net-to-gross, porosity, permeability) per well and its uncertainty range for the Patricia-Baleen gas in place and reserves estimates is covered in Appendix B.

The well layer average parameters were contoured between the wells (Patricia-1, Baleen-1 and Baleen-2) and used as input to a 3-D representation of the Geological model (carried out in Eclipse) and subsequent volumetric calculations (Appendix B).

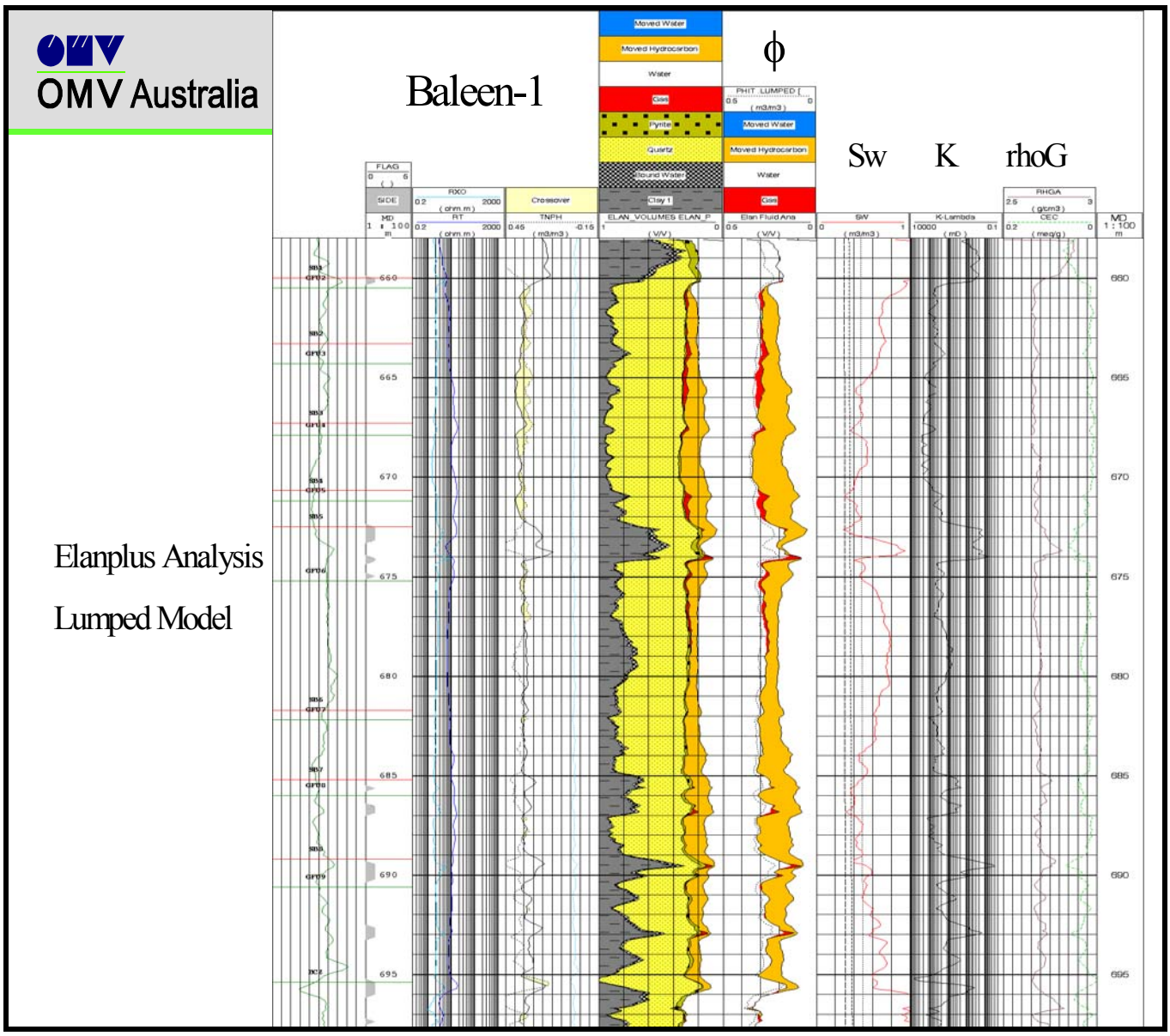

Figure 3.3.1 Baleen-1 Gurnard Reservoir: ElanPlus Analysis with the Lumped Model

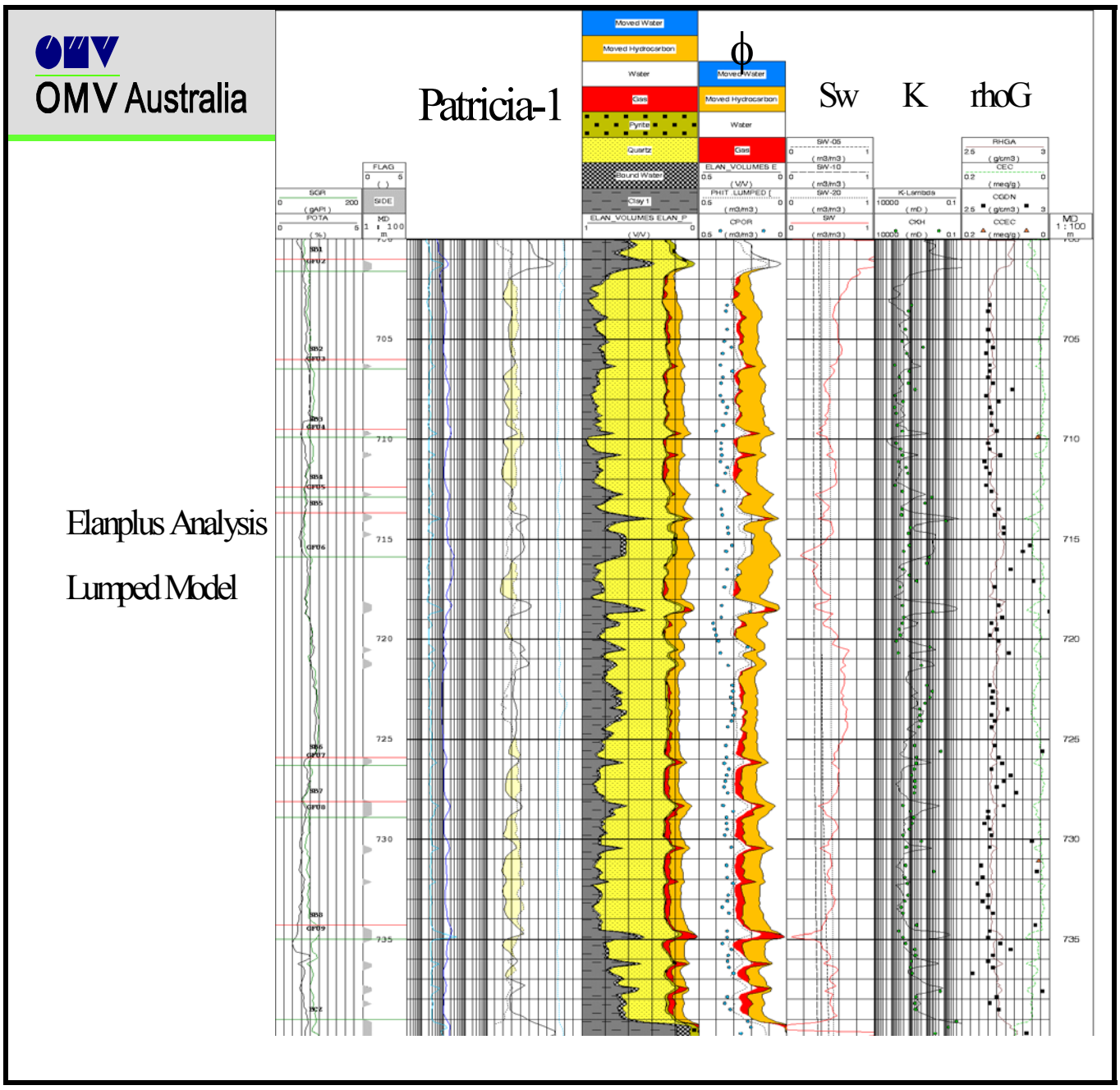

Figure 3.3.2 Patricia-1 Gurnard Reservoir: ElanPlus Analysis with the Lumped Model

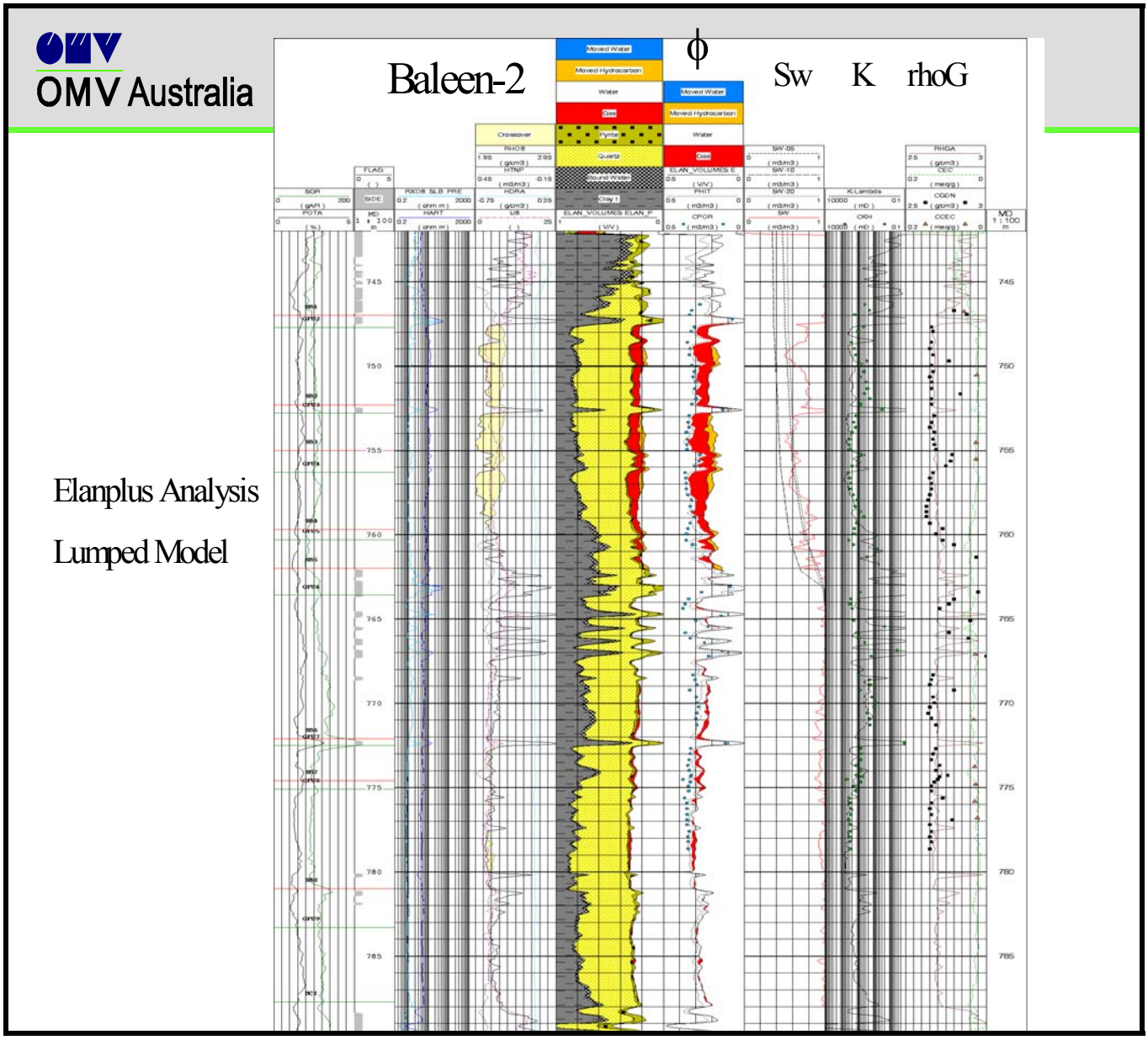

Figure 3.3.3a Baleen-2 Gurnard Reservoir: ElanPlus Analysis with the Lumped Model

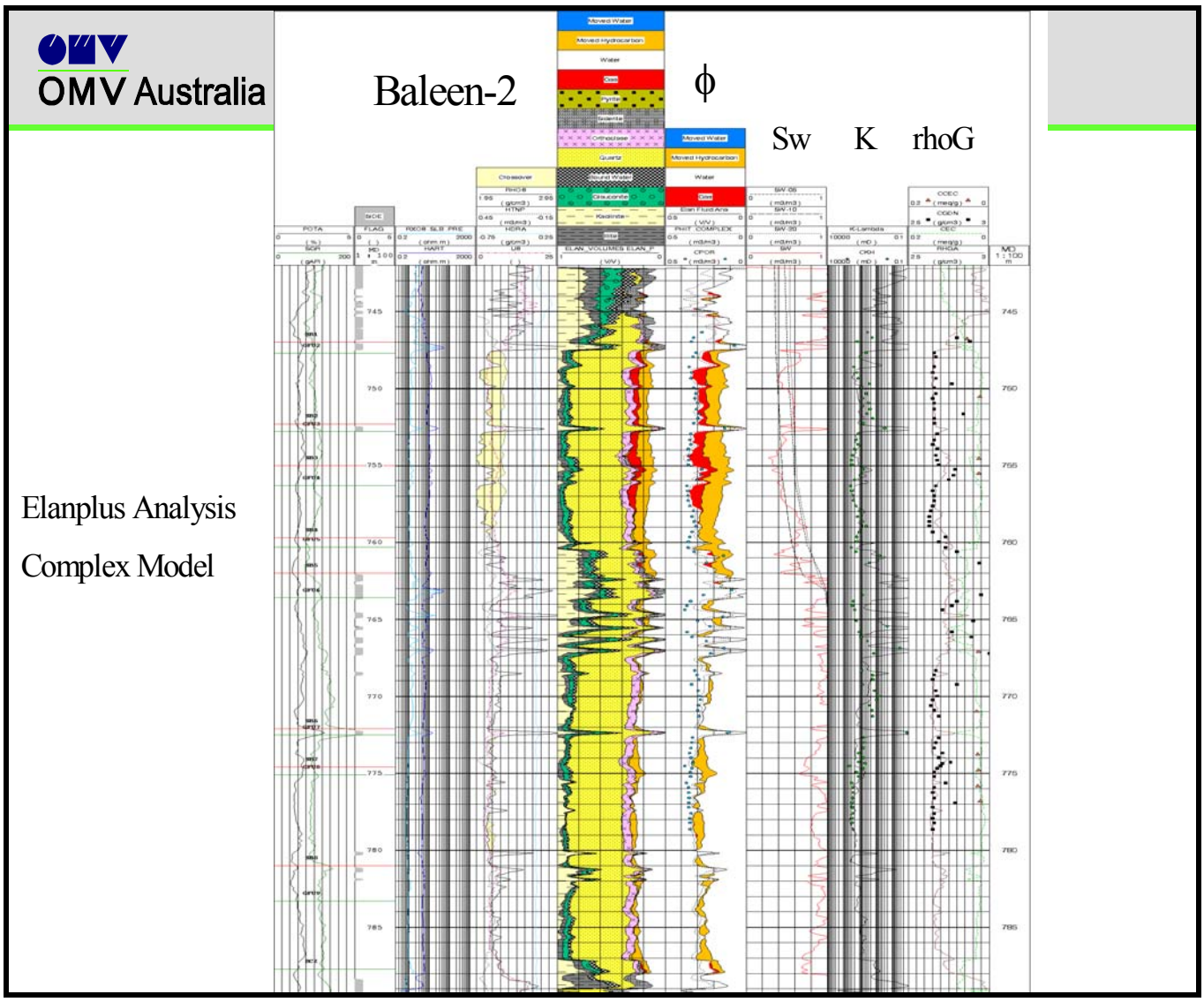

Figure 3 3.3b Baleen-2 Gurnard Reservoir: ElanPlus Analysis with the Complex Model

	Baleen-1 (Lumped)	Patricia-1 (Lumped)	Baleen-2 (Lumped)	Baleen-2 (Complex)
Top Interval	654.5 m	694.5 m	741.0 m	741.0 m
Bottom Interval	695.4 m	739.0 m	787.7 m	787.7 m
Gross Interval	40.9 m	44.5 m	46.7 m	46.7 m
Net Reservoir	38.3 m	41.8 m	40.3 m	40.3 m
Average PIGN (effective porosity)	0.28 m3/m3	0.25 m3/m3	0.27 m3/m3	0.26 m3/m3
Average PHIT (total porosity)	0.31 m3/m3	0.29 m3/m3	0.30 m3/m3	0.30 m3/m3
Average VCL	0.23 m3/m3	0.27 m3/m3	0.27 m3/m3	0.21 m3/m3
Average KINT (calculated permeability)	157 mD	67 mD	73 mD	93 mD
Net Reservoir / Gross Interval Ratio	0.94	0.94	0.86	0.86

Table 3.3.2 Log Analysis Results – Schlumberger July 2000

3.3.4 Fluid Distribution

Fluid Distribution (from wireline logs)	Baleen-1	Patricia-1	Baleen-2
Gurnard Fm			
GDT (Gas-down-to)	686m ss	717m ss	736m ss
WUT (Water-up-to)	N/A	N/A	742.5m ss
Latrobe Grp. CC			
GDT(Gas-down-to)	698m ss	727m ss	N/A
WUT (Water-up-to)	N/A	736m ss	766m ss

Table 3.3.3 Wireline Log Fluid Distribution from Baleen-1 and Patricia-1

The Baleen-1 (1981) exploration well has a Gas-down-to (GDT) at 686m ss and at 698m ss for the Gurnard Formation and the Latrobe Coarse Clastics respectively from the wireline logs. A water leg was not penetrated in either the Gurnard or the Latrobe in Baleen-1.

The Patricia-1 (1987) exploration well has a Gas-down-to (GDT) at 717m ss for the Gurnard Formation from the wireline logs. It also has a Water-up-to (WUT) of 736m ss and a GDT of 727m ss in the Latrobe Coarse Clastics from wireline logs.

The Baleen-2 (1999) appraisal well has a Gas-down-to (GDT) at 736m ss for the Gurnard Formation from the wireline logs. It has a Water-up-to (WUT) of 742.5m ss and 766m ss for the Gurnard Formation and the Latrobe Coarse Clastics respectively from wireline logs.

A Gas Water contact (GWC) was not penetrated in Baleen-1, Patricia-1 or Baleen-2. An original Free water level (FWL) is estimated at 735.6m ss (Appendix C) for the Gurnard Formation.

A current free water level (FWL) and assumed GWC is estimated at 738.2m ss (Appendix C) for the Gurnard Formation in the Baleen structure. There is practically no difference between the FWL and the GWC given the capillarity of the rock.

A current GWC is estimated at 730m ss for the Gurnard Formation in the Patricia structure based on spill point (see section 3.1.3).

4.0 RESERVES, DEVELOPMENT OPTIMISATION AND RESERVOIR MANAGEMENT

4.1 Introduction

The previous GIIP and reserves estimates presented in the Proposed Development Concept in July 2000 did not incorporate the results of the Baleen 2 well and the 3D seismic data. The data is incorporated into this study.

The new seismic data, particularly the amplitude maps, has been used to significantly better define the structures and the gas water contacts. In this application the data quality is exceptionally good, resulting in a relatively narrow range of uncertainty on the gross rock volumes (GRV). In addition the quality of the seismic is such that further analysis of impedance data will be ongoing through the execution phase of the project. The objective of this work will be to better define the internal reservoir architecture and build a detailed geological model in order to optimise the final development well locations and trajectories.

Notwithstanding this ongoing analysis the Patricia-Baleen field is composed of two relatively simple structures lending themselves to a deterministic approach to reserves determinations and development plan optimisation. The very small volumes of gas associated with the Latrobe Coarse Clastics have been discounted, as in previous studies.

The Gurnard Formation Gas Initially in Place was determined using a 3-D reservoir model (Eclipse). This has the advantage of systematically incorporating the rock properties, gas saturation functions and aquifer response. Given the nature of the depletion drive of the reservoir and the limited size of the resource the optimisation of the development plan has been achieved by choosing simple but realistic starting assumptions guided by commercial realities. A network model for the flow system has then been incorporated into the Eclipse model to determine production profiles and reserves.

The sections 4.2 to 4.5 (see below) details the building blocks of the GIIP, the reservoir and network models and reserves range for the most likely development. Section 4.6 describes the optimum development scenario and section 4.7 the reservoir management plan.

4.2 Gas Initially in Place

4.2.1 Gas Rock Volume (GRV) and Layers (Eclipse Model)

A 50m x 50m mesh file of the top of Gurnard Formation was generated based on the 3-D seismic depth map and input to Eclipse GRID as the top surface (see Appendix D).

The Gurnard Formation was divided into 18 layers (Enclosure 3.2.1) based on well log (Baleen 1, Patricia 1 & Baleen 2) correlations and core data (Patricia 1 & Baleen 2) correlations. Good correlation exists between the wells (see Section 3.3.3). In the Eclipse model the top layers (GFU1 and SB1) were excluded as they were considered to be non-pay. Therefore sixteen layers were modelled within Eclipse.

The low permeability siderite bands, seen on the well logs sandwiched between the sand layers, were modelled as individual layers. This enabled sensitivity analysis of the GIIP and the recoverable volumes based on the formation properties of the siderite bands.

Sixteen individual layer maps were generated from contouring the layer thickness as measured at the three well locations. The gross reservoir thickness map from combining the sixteen layers was corrected to honour the gross thickness observed from the good quality 3-D seismic data. This

correction factor was applied to each of the layer thickness contour maps such that the gross thickness from combining the corrected maps matched very closely to the 3-D seismic gross thickness map. The sixteen corrected individual layers were each stacked below the top of structure map to formulate the reservoir architecture.

The 3-D model was initialised with the original GWC at 738.2 m. SS in Baleen and 730 m SS in Patricia.

The model has an estimated gross rock volume of 277 x 10^6 m^3, which is in good agreement with the geophysics' estimate of 269 x 10^6 m^3.

Accumulation	GRV [sqkm*m]
Baleen Total (GWC = 738mss)	186.84
Patricia Total (GWC picked from Seismic)	81.97
Patricia-Baleen Total	**268.81**

Table 4.2.1 GRV for Patricia and Baleen structures from 3-D seismic maps

4.2.2 Rock Properties

The areal distribution of the porosity, net to gross, and permeability (air) per layer were determind by interpolating the assigned layer values at the three wells. The layer values at the wells were determined from core and log data (see Section 3.3.3 and Appendix B).

The air permeabilities were multiplied by a factor of 0.32 in Gurnard flow units. This correction was necessary to conform to insitu kh measurements from DST's (Appendix G) conducted in Baleen 1 and Patricia 1 (Table 4.2.2).

Well	Test	Zone (mRT)	MMscf/d	FFBHP (psia)	Kh (mD-ft)	K (mD)	S
Baleen-1 Gurnard	DST 2A	662-670	6.3	670	2,100	60	3.6
Patricia-1 Gurnard	DST 3A	703-738	24.1	774	2,625	22	0.9

Table 4.2.2 Kh data from Baleen-1 and Patricia-1 DSTs

4.2.3 Gas Saturations

Saturation-height functions were used to estimate the gas saturation in the layers of the Eclipse model where each layer had an assigned saturation-height function based on its rock type.

Based on Baleen-2 capillary pressure curves, three rock types were modelled. As is normally the case, there is a good relationship between irreducible water saturation, Swir, and permeability; Swir's being lower for the higher permeability rock. The higher permeability layers were assigned rock type 1; intermediate quality rock type 2 and the siderite layers were assigned rock type 3 (Table 4.2.3 and Figure 4.2.3).

The capillary pressure curves were not averaged[1] but a representative capillary pressure curve was chosen for each rock-type. A GWC of 738.2m SS for the Baleen structure and 730.0m SS for

[1] The common J-curve capillary pressure curve averaging technique was not applied since this method is considered unsuitable when the range of permeability (0.02 to 300 mD) and Swir (30 to 46) is relatively wide.

the Patricia structure (Section 3.4.4 and Appendix C) were taken as the respective FWLs in the Eclipse model.

Each of the sixteen layers was assigned a rock type based on the layer's average permeability (Table 4.2.3).

S_{wir}	SCAL Sample & Permeability	Permeability Range (mD)	Model Layer
Rock Type 1 -- 30%	S10 – 215 mD	>90	3, 5, 13
Rock Type 2 -- 35%	S5 – 63 mD	40-90	1, 7, 9, 11, 15
Rock Type 3 -- 46% Siderite Layers	S20 – 25 mD	0.02-40	2, 4, 6, 8, 10, 12, 14, 16

Table 4.2.3 Rock types per permeability range

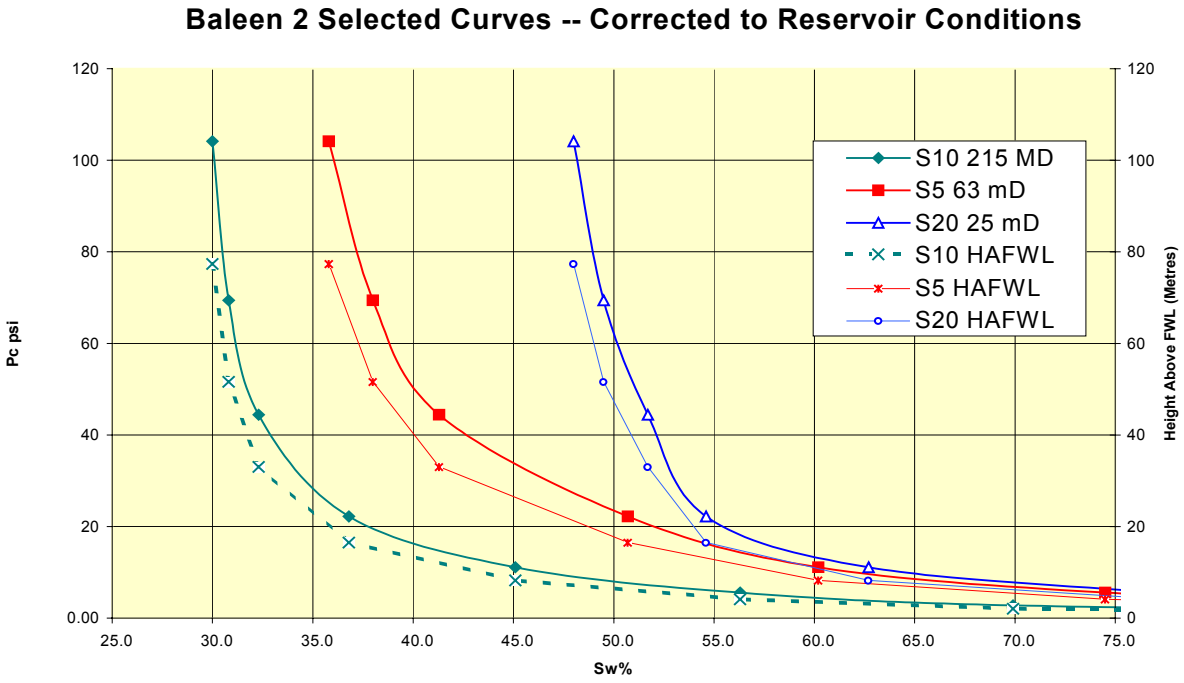

Figure 4.2.3 Saturation-height functions per rock type

4.2.4 Gas Initially in Place Results

The Gas Initially in Place in the areas of interest were estimated to be 63.3 Bscf (Baleen) and 21.3 Bscf (Patricia), giving a total GIIP of 84.6 Bscf.

Layer	1	3	5	7	9	11	13	15	Siderite Layers 2, 4, 6, 8, 10, 12, 14, 16	Total
GIIP (Bscf)	15.9	13.1	12.7	3.3	13.9	4.2	6.4	3.7	11.4	84.6

Table 4.2.4 Gas-in-place volumes per layer (layer 1 being the top layer)

4.3. Gas Reserves

The primary parameters expected to influence gas recovery are fault transmissibility, vertical to horizontal permeability ratio, number and type of wells, well placement, tubing and flowline size,

plant inlet pressure and aquifer influx. An eclipse simulation model was used to estimate these effects.

4.3.1 Reservoir Model

The model has a 42 x 32 x 16 grid (21,504 grid blocks), which covers the entire hydrocarbon bearing areas of interest. The smallest grid block size is about 100m x 100m in the vicinity of the wells, and the largest cells in the flank area are close to 500m x 500m. The reason for choosing a fine grid is to model the well performance as accurately as possible. The vertical section consisted of 16 layers (a k_v/k_h ratio of 0.1 was assumed in the absence of vertical permeability measurements).

The methodology used to populate the model with porosity and saturation is given in section 4.2.

The faults along the north and northwest flanks of the Baleen structure are deemed no-flow boundaries. Other faults are most probably partially or non-sealing due to small throws. The transmissibility across the internal faults was assumed to be unity and then reduced for the sensitivity runs.

The wells were completed in all simulation layers. PVT data was incorporated, as were Kh values from the well tests.

Pressure

The Patricia-Baleen field was modelled using the current (1999) gas pressure estimate of 1073 psia (at datum depth of 738.2m ss) for both the Patricia and Baleen structures. A gas gradient of 0.072psi/m and a water gradient of 1.41psi/m was determined based on well pressure data (Appendix C).

PVT

The gas consists of close to 98% pure methane and contains insignificant quantities of NGL and condensate. The gas properties were obtained using the equation of State (EOS) based on a gas sample collected during the Patricia 1 well test.

Component	Methane	Ethane	Propane	i-Butane	n-Pentane	Hexane+	Nitrogen	CO2
Mole %	97.724	0.28	0.005	0.003	0.003	0.005	0.66	1.32

Table 4.2.5 Gas properties obtained using the equation of State (EOS) on a Patricia-1 gas sample

A gas expansion factor of 72.4 scf/rcf was calculated based on the above gas composition. The gas has a heating value of 36.86 MJ/m^3, which equates to 1.0438 PJ/Bscf.

Relative Permeability

Residual gas saturations were measured by special core analysis to be about 16%. However, these were considered unrealistically low and were adjusted to 25%. The relative permeability curves were generated with Corey exponents of 2.0 for gas and 4.0 for water. The relative permeability curves for the three rock types are given in Appendix D. These assume Swc = Swir viz 0.30, 0.35 and 0.46 for each of the three rock types.

Aquifer

It is expected that the Gurnard Formation in both the Baleen and Patricia accumulations will have weak to no aquifer support. This expectation is based on the geometry of the structure and the relatively low permeability nature of the reservoir.

In general the fields in the Patricia Baleen area have a northern bounding fault. The Baleen field is a three-way dip closed anticline and is bounded to the north by a major fault running east to west and to the south by the Patricia field structure. The Patricia field is a four-way dip closed anticline with some fault dependent closure. The aquifer is open to the southwest portion of the Baleen field and most of the southern part of the Patricia field. The Patricia field is expected to experience some aquifer influx at the tail end of field production. The Baleen field is expected to have even less aquifer influx. The bounding faults are expected to effectively shield the Baleen and Patricia accumulations from aquifer influx.

For strong aquifer support reservoir quality should be in the Darcy range of permeabilities. The Gurnard Formation with average permeabilities of around 50mD does not lend itself to significant aquifer support.

Any aquifer support available to the Latrobe Coarse clastics is not expected to be fully available to the Gurnard due to an effective permeability barrier at the interface between the two formations.

Simulation results (Appendix E) show that the infinite aquifer does not significantly change well gas rates or reserves. Nonetheless, maximum formation water production rates at the Patricia well increased from 70 to 100 stb/d. No formation water was predicted in either case for the Baleen well.

Well Locations

The development well locations in the Baleen and Patricia structure were modeled to be located at the top of structure and angled to delineate all layers whilst staying above the gas water contact. Sensitivities evaluated on well number and type support the conclusion that two wells will effectively recover the reserves (Appendix H).

Vertical and Horizontal Tubing/Pipeline Performance

The Beggs and Brill correlation was used for modelling horizontal flow including the near horizontal section of the two wells and the flowlines. This correlation is known to be relatively conservative and was selected in the absence of reliable calibration data. Gray's correlation was used for vertical flow in the wells.

4.4 Network model

The benefit of a network model is that it allows individual well productivity to be modelled more accurately allowing for any well back-out components and the use of more accurate volumes through the pipeline to shore.

The network model (Fig 4.4.1) for a two-well case with the sub-sea manifold located at the Baleen wellhead was set up using the VFP_i and Geoquest module.

The Baleen well was assumed to be 500m at 80° in a structurally high culmination, followed by 800m horizontally towards an adjoining culmination with a further 400m horizontal section in this culmination. The well was completed with 4.892" ID tubing. A 2.5 km 5.984" ID in-line was assumed from the Patricia well which was modelled as an 80° 450m well with 2.992" ID tubing. Expandable Sand Screens with 4.89" ID were assumed for both wells. The manifold was

connected to flange upstream from slug catcher at drill-out point onshore via a 23km 11.024” ID (280mm) pipeline.

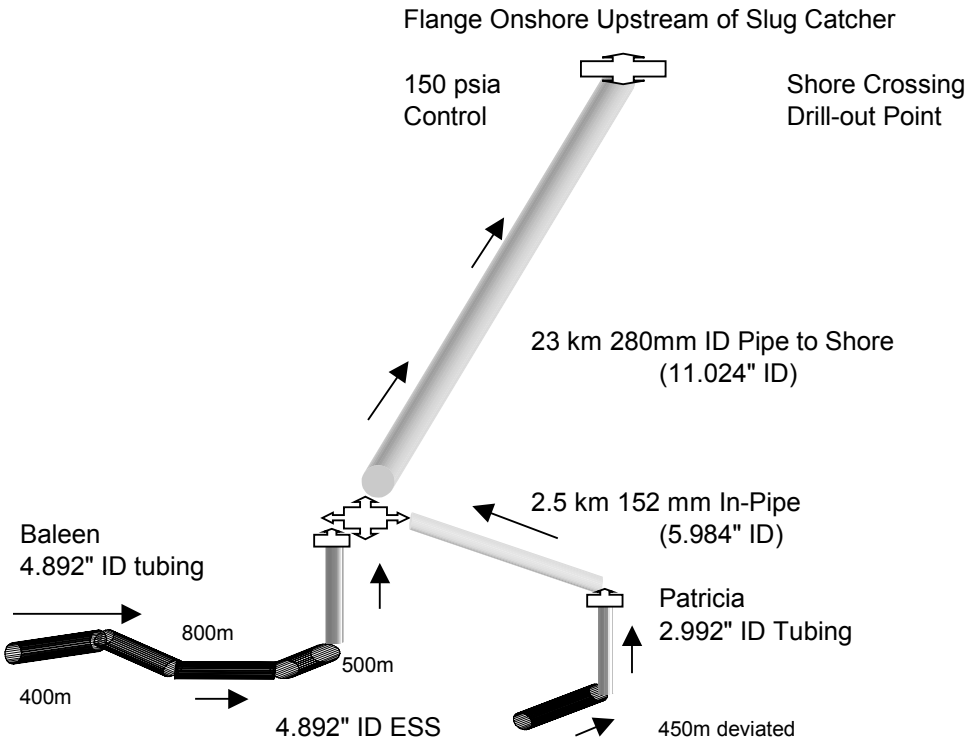

Figure 4.4.1 Patricia-Baleen Network Model

Wellbore Skin

The DST analyses (Appendix F) in Baleen 1 and Patricia 1 indicate that formation damage was negligible, and the pressure drop due to turbulent flow was small. Nevertheless a skin factor of 5.0 was applied to the wells to account for potential wellbore pressure losses associated with expandable sand screens (ESS).

Tubing Size

The most likely tubing sizes for the Baleen well and the Patricia well are 5 ½” OD tubing (4.892” ID) and 3 ½” OD tubing (2.992” ID) respectively (see Appendix G).

Plant Capacity

A plant capacity of 50 MMscf/d was selected as a base case. This represents a reasonable rate for initial marketing, strategic and field life considerations. Final optimisation of the plant capacity will be dependant on commercial negotiations with the equipment suppliers.

Plant Inlet Pressure

The base case Plant inlet pressure is 150 psia. This has been selected as giving the best compromise between minimising the compression ratio required to enter the EGP and achieving an acceptable ultimate recovery from the depletion drive of the reservoir. Sensitivities run at an inlet pressure of 300 psia at end field life indicated a loss of around 10% in ultimate recovery.

Reservoir Abandonment Pressure

Reservoir simulation modelling shows that at abandonment, the average reservoir pressure would be around 300 psia (Figure 4.4.2). Since the drive mechanism is expected to be of a depletion type, the reservoir pressures are expected to be relatively uniform with the lower permeability zones experiencing slightly lower pressure depletion.

4.5 Reserves Results

The reserves in the areas of interest were estimated to be 44.3 Bscf (Baleen) and 14.9 Bscf (Patricia), giving a total reserves of 59.2 Bscf.

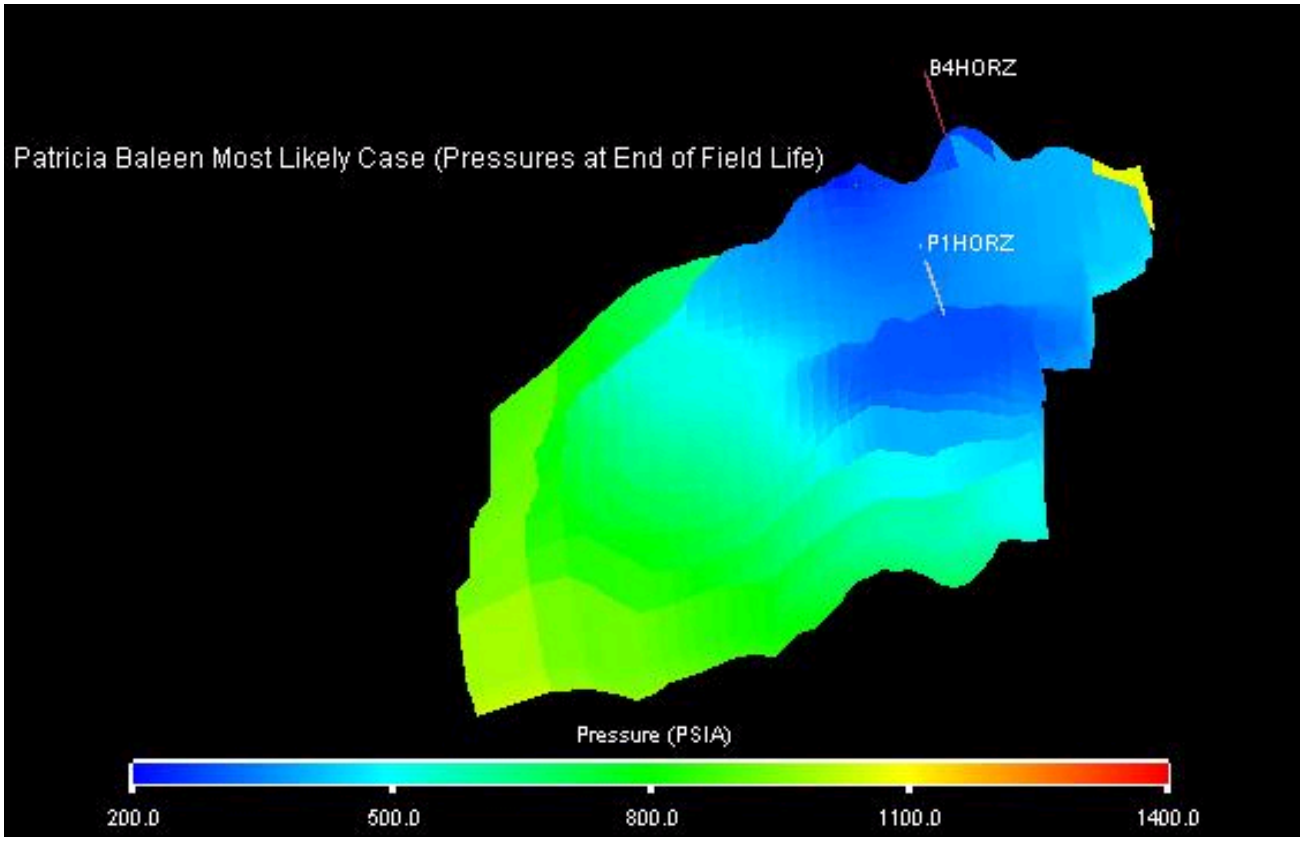

Figure 4.4.2 Patricia-Baleen field pressure at end of field life

4.6 The Optimum Development Scenario

Sensitivities were carried out on the number and type of wells to maximise ultimate recovery (Appendix H). The development requires a minimum of two wells.

The most likely case simulation model was used to determine the optimum development scenario for the Patricia-Baleen field.

This optimum development (base case development plan) consists of:

- Two wells, one each in the Baleen and Patricia structures (a 1500 m well in the Baleen structure and a 500m well in the Patricia structure)
- 4.892" ID tubing for the Baleen well and a 2.992" ID tubing for the Patricia well.
- A plateau rate of 50 MMscf/d.
- A 11.024" ID pipe to shore. The use of a larger diameter pipe to shore would have little to no impact on ultimate reserves due to the relatively low pressure losses at end of field life when production rates are low.
- Plant water (produced and condensed) handling capacity of 150 bbls/day.

4.6.1 Sensitivities to the Optimum Development Scenario

Sensitivities were carried out on the robustness of the base case development for downside and upside cases of the reservoir model. The downside and upside cases of the reservoir model were determined from parameter variation to the most likely reservoir model (Table 4.6.1). This gave a range in the GIIP from 79.6 Bscf (P90) to 98.3 Bscf (P10). The base development plan yielded a range in the Reserves (Figures 4.6.1 and 4.6.2) from 49 Bscf (P90) to 67.6 Bscf (P10) based on an eight year field life.

Field productivity after eight years declines to 5 MMscf/d, which is considered an economic cutoff rate, based on data currently available. Field production will continue beyond this time if economically viable.

Parameter	Downside	Most Likely	Upside
Top of Structure	Seismic depth map	Seismic depth map	Seismic depth map
GRV	Matched to Seismic	Matched to Seismic	Matched to Seismic
Layer Thickness	From Logs	From Logs	From Logs
		(Gross control from seismic)	
GWC Baleen (m SS)	738.2	738.2	738.2
GWC Patricia (m SS)	728	730	734
Fault Transmissibility	0.0	1.0	1.0
Porosity (sand)	From Logs (21 to 34%)	From Logs (21 to 34%)	From Logs*1.10
Porosity (siderite)	15%	20%	25%
N/G (sand)	From Logs (0.8 to 1.0)	From Logs (0.8 to 1.0)	1.0
N/G (siderite)	1.0	1.0	1.0
Rock types (Type 1)	Layers 3, 5, 13	Layers 3, 5, 13	Layers 3, 5, 13
Type 2	1, 11	1, 7, 9, 11, 15	1, 7, 9, 11, 15
Type 3	Siderite + 7, 9, 15	Siderite Layers	Siderite Layers
Sw (three rock types)	Capillary Curves	Capillary Curves	Capillary Curves
Permeability (sand)	From Cores*0.32	From Cores*0.32	From Cores*0.32
Permeability (siderite)	0.02*0.32 mD	1 mD	10*0.32 mD
(Sgr %)	25	25	16
GIIP (BSCF)	**79.6**	**84.6**	**98.3**
Reserves (BSCF)	**49.0**	**59.2**	**67.6**
Recovery Factor (%)	**61.6**	**70.0**	**68.8**

Table 4.6.1 Parameter Variation used to determine range in GIIP and Reserves

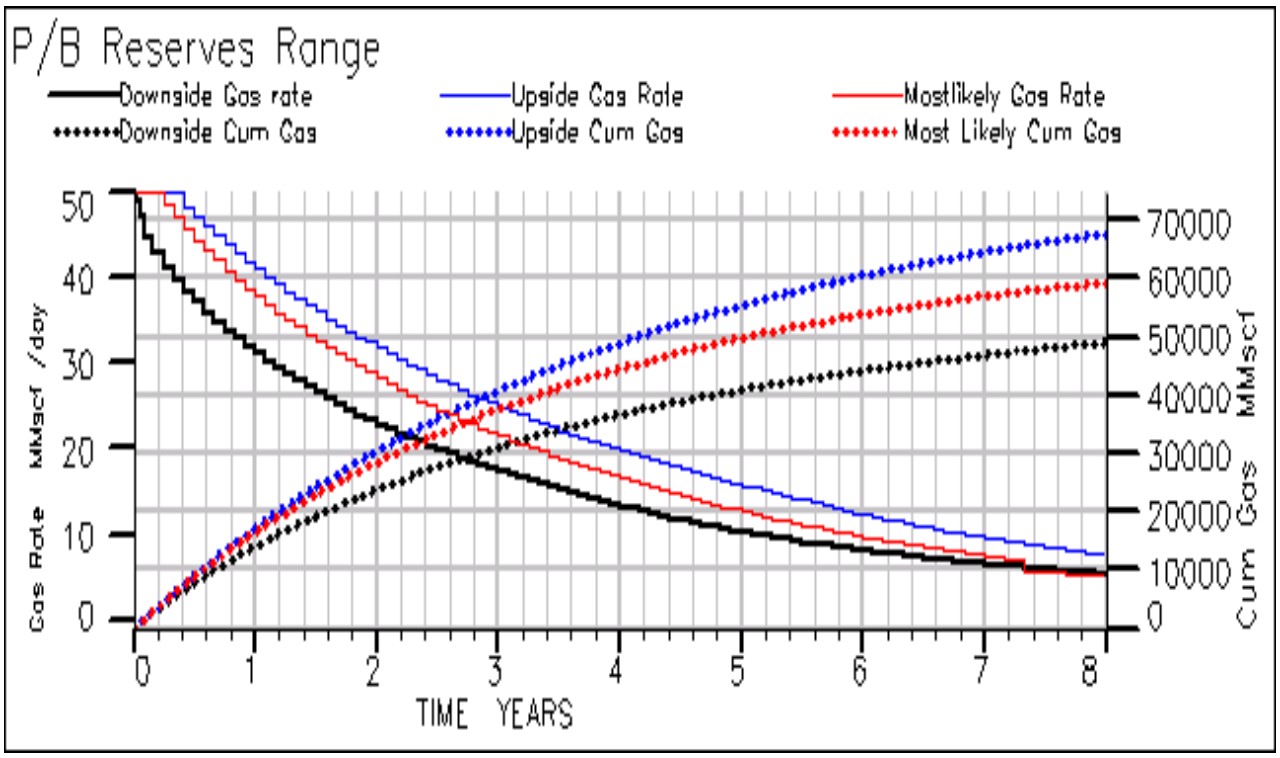

Figure 4.6.1 Production Profiles for Patricia-Baleen field reserves range

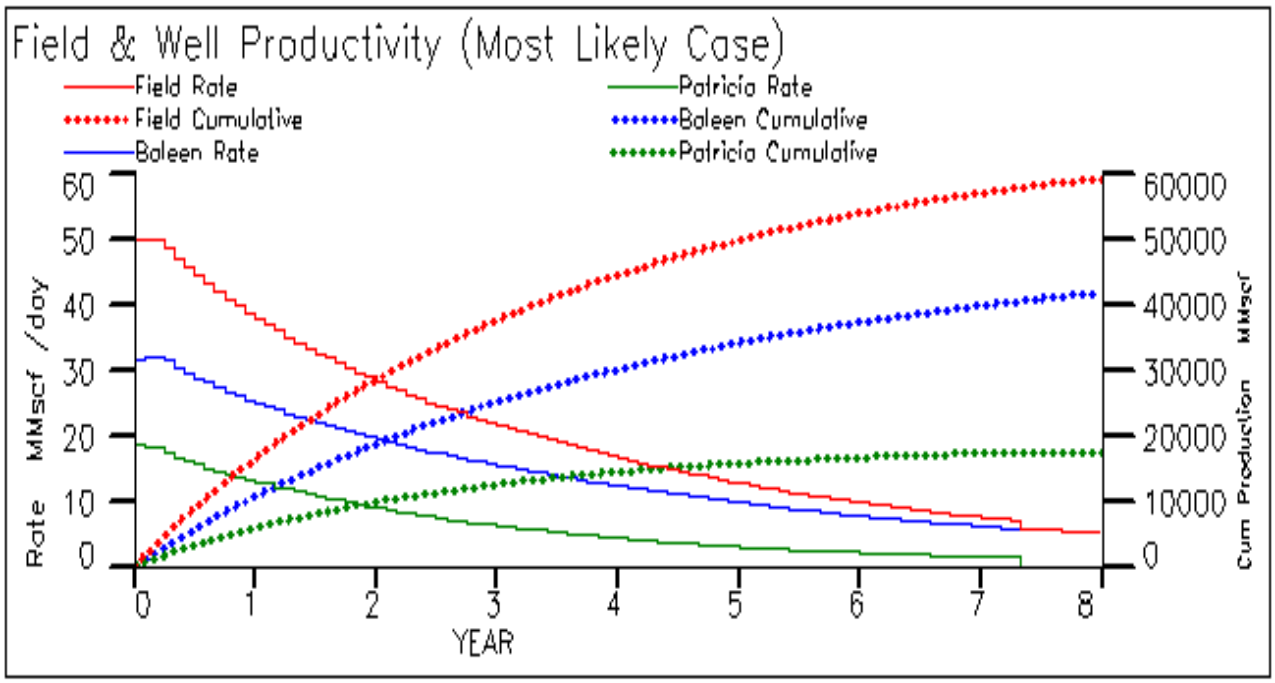

Figure 4.6.2 Production Profiles for Patricia and Baleen wells for most likely case

4.7 Reservoir Management Plan

The objective of the reservoir management plan is to ensure optimal recovery of the gas reserves consistent with the development plan.

A first class 'static database' is populated with wireline log and core data from three discovery wells, plus extensive excellent quality 3D and 2D seismic data. Further work on acoustic and elastic impedance is underway to further enhance the understanding of the reservoir architecture and likely drainage patterns (see Section 3.1.6).

The dynamic database, currently populated with the results of flow tests in two vertical discovery wells, will be supplemented with flow tests on the initial completion of the horizontal development wells. These data has allowed an effective reservoir simulation model to be built to predict reservoir, wells and pipeline performance. Subsequent data will be restricted to measurements mostly onshore and at the subsea manifold.

4.7.1 Well Tests

As part of the well completion, it is planned to flow each well to clean up the drilling and completion fluid and then carry out a short term production test. Gauges will be run on wireline which will restrict the depth of measurement to angles around 45^{o}. Effectively the deepest measuring point will be at the bottom of the 5½" tubing around 645m. The objectives of this test will be to confirm well deliverability, fluid composition, vertical lift performance and reservoir pressure against prediction. It will also be possible to confirm the efficiency of the expandable screens in preventing sand production.

Consideration will only be given to obtaining additional downhole data such as pressure data or PLT data, if the well deliverability deviates significantly from prediction and if the remaining reserves justify the cost of remedial activities.

4.7.2 Well Production and Pressures

The development will consist of two subsea wells tied back to a subsea manifold, a pipeline to shore and an onshore plant.

Well flowing pressures and temperatures will be continuously monitored at the subsea manifold. It is intended to allow the two wells to produce freely to the onshore plant. Choke control can be applied at the manifold if required to balance production from the wells. This will apply during the plateau period, however effectively, for most of the field life, both wells will produce at maximum capacity to the plant.

Total production will be measured on shore using fiscal meters. Production allocation to the wells will be achieved utilizing all test and production data. If field performance differs from that predicted it may be desirable to re-test individual wells. This will be done by shutting in or choking back one well and measuring the flow from the other well onshore.

4.7.3 Reservoir Performance

The reservoir model described in Section 4 will be utilised to track reservoir performance. Flow performance curves will be incorporated to allow the whole system to be modelled back to the subsea manifold.

It is likely that some minor modifications to the reservoir model, in particular layer thicknesses and well productivity, will be incorporated as a result of information obtained in the development wells. In addition, the initial well tests will allow the initial reservoir pressure and well productivity data (kh, skin, vertical lift performance) to be measured.

Reservoir performance will be monitored by matching the simulation model against production data on a regular basis. Well pressures and temperatures will be monitored continuously at the manifold. The produced fluid will be dry gas with very little liquid. An accuracy of some 5-10% can therefore be expected in predicting the pressure drop back from the subsea manifold to the bottom of the tubing. An improvement on this accuracy is anticipated by utilizing the data from the initial well test to tune the model performance to actual life.

Use of the simulation model will allow reservoir performance changes to be identified as they occur. In addition, the model will be used as a predictive tool to estimate ultimate recovery and provide estimates of the benefit of well intervention, or additional development.

5.0 DEVELOPMENT FACILITIES

5.1 Overview

The Patricia-Baleen field will be developed to supply gas into the Eastern Gas Pipeline (EGP). This pipeline is operated by Duke Energy and connects Longford to Horsley Park, near Sydney. An access point into the pipeline near Orbost is envisaged.

A stand-alone development is contemplated initially. Consideration has been given to future use of the facilities for transporting, processing and storing third party gas from other nearby fields.

The development will comply with applicable Commonwealth and State legislation and regulations. Government approvals will be sought as required. Each submission for consent to construct or operate a part of the facilities will demonstrate that it is suitable for the intended purpose and that risks to people and the environment have been reduced to levels as low as reasonably practicable.

A development incorporating the following features is proposed:

- Two new development wells will be drilled
- The wells will be vertically drilled with near-horizontal sections within the reservoir
- Offshore facilities will comprise an all subsea development, controlled from the onshore plant
- A 12" pipeline will be installed from the subsea manifold to shore
- The onshore plant will be designed for 60 TJ/d and will comprise a single train of separation, dehydration, produced water disposal and metering facilities. Redundancy will be provided in the sales gas compression to accommodate peaks in demand and unscheduled downtime. The treated gas will meet the quality specification and entry pressure requirements for the EGP
- A drilled beach crossing will be provided for the pipeline shore crossing
- Provision for tie-in of additional gas wells, future discoveries and third-party gas shall be included in the offshore facilities
- The onshore plant shall be laid out to facilitate expansion to handle additional third party gas

5.2 Offshore Facilities

The major offshore facilities comprise the subsea production system and pipeline. The drilling of the wells and their associated completion equipment is covered in section 6.

5.2.1 Subsea Production System

The sub sea system will comprise subsea wells linked via a manifold to a pipeline for free flowing the produced fluids to shore.

A multiplex electro-hydraulic control system is proposed, with electro-hydraulic functions between the onshore control room and the manifold, and simple hydraulic controls from the manifold to the wells. The control system will provide for four wells, two wells as part of the Patricia-Baleen development and two for future use.

The Subsea production system will comprise the following components:

- Subsea christmas trees
- Wellhead controls and hydraulic systems for opening and closing wellhead valves and sub surface safety valves
- Chokes, located at the manifold and remotely controlled from onshore with position indication
- Flowlines between the wells and the manifold
- Manifold for four wells
- Support structures, guidebases, structures to be designed to withstand potential snagging
- Cathodic protection for manifolds, flowlines, and guide bases, as appropriate
- Provision for intelligent pigging of the pipeline
- Provision for a tie in of third party gas
- Corrosion inhibitor injection either into each well stream or into the pipeline inlet
- Instrumentation and data gathering at the manifold for collecting process data and status indication
- Umbilical connections from wellheads and manifold to onshore plant, the umbilical shall contain duplicated hydraulic and signal cables. The umbilical shall also provide electrical power requirements, if any, to the metering and data gathering systems
- Umbilical termination at the onshore plant
- A hydraulic power unit located at the onshore plant
- An electric power unit at the onshore plant
- Chemical injection skid including storage, pumps and metering at the onshore plant
- A man/machine interface (VDU) type control interface in the onshore plant control room, this will be located in a control room alongside the control VDU for the onshore plant

Pipeline corrosion will be monitored electronically at the manifold as well as by regular measurement of iron content and residual corrosion inhibitor in the water at the plant. Provision will be made in the design for running intelligent pigs, if required, but permanent launching and receiving facilities will not be fitted.

Continuous hydrate inhibitor injection is not required, a chemical injection point shall be provided upstream of the choke in case hydrate inhibitors are required for well start up. The umbilical shall have the capability to transport hydrate inhibitor. The spare corrosion inhibitor line may be used for hydrate inhibitor injection.

A suitable coating system will be applied to all subsea components, corresponding to the design life.

Diverless methods for maintenance and repair will only be adopted where these are shown to be cost effective compared with diver intensive techniques. Where possible, systems will be designed for maintenance free operation during the life of the field.

The control system will be designed to provide full redundancy so that there is no loss of control or production following the failure of any single component within the control system, including the hydraulic power unit. The control system shall be configured so that in event of loss of signal all production is stopped within 30 minutes.

All flow line and manifold piping will be designed in accordance with AS 2885.

Marine growth will be considered, from mudline to Chart Datum (+) 2.0 m.

5.2.2 Offshore Pipeline

Offshore pipeline diameter will be 12" nominal bore.

The offshore pipeline will be designed to AS 2885 and other applicable codes. The pipeline will be designed to prevent failure due to:

- Excessive yielding from internal pressure or external loadings
- Lack of on bottom stability
- Buckling
- Corrosion, both internal and external

The following design conditions will be considered:

- Functional
- Environmental
- Installation
- Hydrotest

The mechanical design and stabilisation will provide for simultaneous loads due to internal pressure at design pressure conditions and environmental loads corresponding to the 50 year return period.

The following environmental data return periods shall be considered for the design of the pipeline:

- The one year return period shall be used for analysis relating to the installation of the pipeline.
- The 50 year return period shall be used for the installed condition.

Pipeline stabilisation will be provided, using concrete weight coating or alternative design methods. An anti-corrosion coating and sacrificial anodes shall protect the offshore pipeline externally.

The pipeline shall be capable of being intelligently pigged. Bends and fittings shall be compatible with intelligent pigs.

5.3 Onshore Facilities

5.3.1 General

The purpose of the Onshore facilities is to receive the produced fluids from the offshore pipeline, process and compress the gas to produce sales specification gas at a suitable pressure for delivery into the EGP pipeline. The facilities will be sized to process a maximum of 60 TJ/day of sales gas (ie: net of fuel gas requirements) and shall comprise the following main elements:

- Facilities for temporary Pig Receiving
- Separation
- Compression
- Dehydration
- Odorisation
- Metering
- Produced water handling and disposal
- Low Level Flare system
- Utilities
- Power Generation
- Fire and Gas detection facilities
- Chemical Injection
- Central control room for operation of both offshore and onshore facilities

The onshore plant including piping, structures and equipment shall have external coating suitable for an exposed coastal, salt laden environment.

5.3.2 Pipelines

The location of the onshore plant is still to be finalised however the preferred location is approximately 2-3km distant from where the offshore pipeline comes ashore downstream of the dune crossing (Refer EES document for plant location options). To minimise pressure drop the onshore feed line will be 16” NB and built to the same specification as the offshore pipeline but electrically isolated for corrosion purposes. Process fluids will flow through this feed line to the inlet separator.

A transmisson pipeline, 10” nominal bore is sized for a flowrate of 200 TJ/day and will be approximately 10 km in length to the location of the tie-in point to Duke Energy’s EGP at the Orbost Main Line Valve Station. The sizing of the sales gas line allows provision for processing of future third party gas. The transmisson pipeline will be buried and mostly laid alongside established roads and through farmland avoiding areas of state forests.

5.3.3 Pig Receiver

The pipeline will terminate at the onshore plant site with either a pig receiver or facilities suitable for housing temporary pig receivers. The receiver will be designed for receiving intelligent pigs from the pipeline. The internal diameter of the inlet of the pig receiver shall be identical with the pipeline internal diameter.

5.3.4 Separation

The produced fluids from the pipeline will enter a two phase inlet separator / slug catcher. Water from the separator will be discharged to the produced water handling and disposal system. The gas from the inlet separator will be fed to the compression system.

5.3.5 Compression

Based on a gas arrival pressure of 1.0 MPag it is anticipated that the compression will be three stage and multi-train. The compressors will be reciprocating with each train driven from a single gas engine. There may be an opportunity to increase the arrival pressure to 2.8 MPag during the first year of operation and work is currently underway to evaluate the benefit to life cycle cost of doing this. Under this scenario the installed compression in year one will be significantly less.

Compressor discharge pressure initially needs to be sufficient for the gas to enter the EGP at 14.9 MPag. This may later increase to 16.5 MPag dependent upon an anticipated change to the Australian Pipeline Specification AS2885.

Compression requirements are based on a depletion type profile of the gas reservoir. The most effective life cycle cost management is to match installed compression horsepower to the production profile and consequently compression will be removed successively through the field life.

Compressor after-coolers will be air cooled fin fan exchangers and driven by the gas engines. Water condensed in the after coolers shall be separated in the suction scrubbers and directed to the produced water handling and disposal system.

5.3.6 Dehydration

The gas will be dehydrated using Tri-ethylene glycol in an absorber column. The optimum location of the dehydration unit will be determined during detailed design but it is likely to be between the second and third stages of compression. Dry gas is sent to the next stage of compression and the water rich TEG is regenerated in the glycol regeneration unit. Lean TEG is then returned to the gas/glycol contactor. Water that is driven off during regeneration is vented to atmosphere.

5.3.7 Metering

A sales gas metering system will be installed at the tie-in point to the Eastern Gas Pipeline.

The metering system shall comprise an ultrasonic dual meter run of 60TJ/d capacity rated to 1500lbs. The meter run shall be configured such that it can be operated in series or parallel with a check meter for calibration and verification purposes. The metering shall include a Gas chromatograph system, for determining gas composition and gross heating value, and a moisture and H_2S analyser. A filter system shall also be installed to ensure that the gas delivered is dust and oil free. A SCADA system shall be provided to transmit the sale gas metering data to the field operating Company and the operator of the Eastern Gas Pipeline.

5.3.8 Produced Water Disposal

Produced water from the inlet separator and compressor suction scrubbers are routed to the produced water degasser vessel for separation of dissolved gases.

Water from the produced water degasser shall be discharged into a produced water tank. The water will be pumped from the tank to a suitable location for disposal, for example to further water treatment areas such as an evaporation pond or via a 2” pipeline to the Orbost sewage farm which will be the most likely recipient of the waste water products.

5.3.9 Shutdown Relief and Vent System

Pressure vessels, compressors and other equipment containing hydrocarbon gases under pressure will be provided with pressure safety valves (PSVs). A blowdown system will be provided to depressurise pressure vessels, compressors, coolers and so forth.

Automatically operated isolation valves will be provided at the battery limits of the onshore plant on both the feed and delivery gas pipelines to limit the inventory of gas in an emergency conditions. The plant will be provided with a relief and vent system for discharge of PSVs and blowdown valves. The system shall comprise a collection header, a knock out drum and a low level flare at a safe location.

5.3.10 Utilities

Plant utilities will comprise:

- Electricity shall be supplied either from the local grid or generated on site, and facilities will include a distribution panel and motor control centre
- A compressed instrument air system shall be provided for valve actuation
- Potable water supplies for ablutions and safety shower
- Drainage systems for the handling of oily water systems and storm water run off
- Fuel gas conditioning

5.3.11 Control, Instrumentation and Communications Systems

The plant control system will comprise electronic field instrumentation connected to a PLC type control system with a VDU interface located in the control room. The control system will also provide emergency shutdown and depressurisation capabilities for the plant.

Controls for the offshore facilities shall be located alongside the plant control VDU to enable the complete system to be operated by a common operator. The control building will also house the communications system for the umbilical termination for the subsea control system.

5.3.12 Fire and Gas Detection

Fire and gas detection shall be provided at suitable locations throughout the plant. The plant shall shutdown automatically on confirmed fire detection including closure of battery limit valves to isolate the plant from the gas inventories in the feed and delivery pipelines. Blowdown will be initiated manually from the control room. Gas detection will cause alarm annunciation only.

Fire fighting will be provided by fire extinguishers (hand held and trolley or trailer mounted). No fire ringmain system will be provided. Water and suitable hose connections shall be provided for use by the local fire fighting authority. Gas engine drivers for compressors shall have CO_2 flood systems in the driver enclosures.

5.3.13 Environmental Protection

The plant shall be designed to minimise environmental impact. Venting of hydrocarbons shall be minimised. Equipment selection shall take fuel and power consumption into consideration.

Paved and / or bunded areas will be provided under equipment which may have liquid discharges due to operation or maintenance activities, eg Lube oils, chemicals, hydraulic fluids, diesel fuel systems. Liquids collected will be directed to local sumps for collection/disposal.

6.0 DRILLING AND COMPLETION

6.1 Introduction

The proposed field development is to drill and complete two horizontal sub-sea wells. Details of the drilling and completions programs are provided below.

The Baleen well will be equipped with 5-1/2" production tubing and have an approximate reach of 1.5km through the reservoir. The Patricia well will use 3-1/2" tubing and have an approximate 450m reach. High angle completion sections will be used in both wells to ensure optimal drainage of the reservoir.

6.2 Exploration Drilling History

Three vertical exploration wells were drilled in the Patricia Baleen Gas Field (Table 6.2.1).

Well	Summary Information	Results / Status
Baleen 1	Spud Date: 4 Nov 1981 TD: 1030 mMD Spud to TD: 12 days Total Duration: 27 days	Well tested Plugged & abandoned
Patricia 1	Spud Date: 26 Jun 1987 TD: 900 mMD Spud to TD: 7 days Total Duration: 25 days	Well tested Suspended as gas producer
Baleen 2	Spud Date: 11 Oct 1999 TD: 895 mMD Spud to TD: 6 days Total Duration: 13 days	Well logged Plugged & abandoned

Table 6.2.1 Summary of Patricia Baleen well information

No significant drilling problems were experienced and no shallow gas was encountered on any location.

Formations are the same for the Patricia Baleen field development wells and similar well designs will be used for the wells.

6.3 Drilling/Completion Program

6.3.1 Drilling Program

The drilling and completion plan is based on information gained from the exploration wells. The Baleen 2 well is a direct offset well which is particularly relevant having been drilled very recently with currently available technology and drilling systems.

A summary of planned well hole sizes is given in Table 6.3.1.

Hole Size	Formations	*Approx. Depth* **(mTVD)**
36” (914 mm)	Gippsland Limestone	150
17-1/2” (445 mm)	Gippsland Limestone	450
12-1/4” (311 mm)	Gippsland Limestone, Lakes Entrance Formation	670
5-7/8” (149 mm)	Lakes Entrance Formation, Gurnard Formation	730

Table 6.3.1 Planned Well Hole Sizes with Depth

6.3.2 Casing Program

A summary of the hole sections and casing program for the development wells (Figure 6.3.1 and Figure 6.3.2) is given in Table 6.3.2.

Description	Casing Size	Approx. Setting Depth	
		mMD	mTVD
Conductor	30” (762 mm)	150	150
Surface Casing	13-3/8” (340 mm)	450	450
Production Casing	9-5/8” (245 mm)	750	670
Production Liner	ESS	1,250 – 2,000	730

Table 6.3.2 Borehole Sections and Casing Program

Carbon steel is planned for all casing strings and a conventional subsea wellhead will be used.

The conductor string will be cemented back to seabed.

The surface casing string will be set in the Gippsland Limestone to provide pressure integrity prior to drilling into the objective with the 12-1/4” (245 mm) hole section. The surface casing string will be cemented back to seabed. A formation integrity test will be carried out at this point, to ensure that good quality cement exists around the casing shoe, prior to drilling into the Gurnard Formation. Production casing will consist of 9-5/8” (245 mm) casing set into the top of the Gurnard Formation. The casing will have premium connections and be cemented back to the seabed.

It is proposed to run nominal 4" expandable sand screens (ESS) and expand these with a rotary expander tool to conform to a 5-7/8” (149 mm) open hole. The screens will be run on a liner hanger to be set below the kick-off point and sealed with a liner-top packer.

As far as possible equipment will be standardised between the two wells. In theory, as Patricia only requires 3-1/2" (89 mm) tubing (Section 4.4 and Appendix G) it would be possible to slim down the well casing design compared to Baleen. However this would require two separate sets of equipment together with back up for drilling and completion adding increased costs and complexity to the operation and logistics. The same basic completion design for both wells will be maintained except for the tubing size.

6.3.3 Drilling Fluid Program

An optimum drilling fluid program is of primary importance to ensure that the development wells are drilled successfully with a minimum amount of risk.

Seawater is used as the drilling fluid for the first two hole sections, supplemented with high viscosity sweeps for hole cleaning.

An inhibitive potassium chloride/polymer will be utilised to drill the 12-1/4" hole section through the Gippsland Limestone and the Lakes Entrance overlying the reservoir.

A low solids, inhibitive potassium chloride/polymer drilling fluid will be used to drill the 5-7/8" hole section to minimise formation damage through the Gurnard Formation reservoir. Pilot testing of the proposed drilling fluid will be conducted to establish compatibility with the reservoir and the expandable sand screens (ESS) to be deployed in the reservoir section.

6.3.4 Wellhead / Tree

A conventional subsea wellhead with an 18-3/4" (476 mm) housing will be used with a conventional dual bore subsea wellhead. Horizontal tree technology is not warranted with the shallow water depth and zero intervention design philosophy of the well.

6.3.5 Completion Design

The optimum tubing size was determined as 5-1/2" (140 mm) for Baleen, providing a monobore type completion, and 3-1/2" (89 mm) for Patricia to ensure efficient liquids lifting and enhance overall gas recovery from the well (Appendix G).

The completion has a 10-year design life and as far as possible equipment is to be standardised between the two wells, not withstanding the different tubing sizes required. This will minimise cost and complexity of design, procurement, operations and backup equipment requirements.

Based on calculated corrosion rates, the tubing and all flow-wetted areas of downhole equipment will be 13 Chrome or of equivalent corrosion resistant material. 13Cr material is also capable of tolerating H_2S (as measured in DSTs – Appendix F) from the underlying Latrobe Formation, should this be encountered during the production life. Premium connections have been specified to reduce the risk of gas leaks and a build up in annular pressure.

A hydraulic set production packer will be set above with a tailpipe assembly run inside the liner top extension. The packer will be run on the production tubing using a latch assembly. This avoids the use of any dynamic seals and minimises space-out requirements.

A hydraulically operated, tubing retrievable sub-surface safety valve (TRSSV) is planned to be set at around 60m below the seabed. Flow couplings should be installed either side of the TRSSV to accommodate any erosive wear due turbulent flow. A nipple profile is likely to be included by default (although running a replacement wireline valve in these short lifetime subsea wells may not be economically justified).

A liner hanger will be used to run the expandable wire screens into the open hole. It will be run with an integral liner top packer to provide a seal to the tubing annulus. It is proposed to set the liner hanger where the hole is near vertical.

The hanger will be set hydraulically. Once the liner hanger is set, the liner top packer can either also be set hydraulically, or the running tool disengaged and the packer weight set using the running string. The packer will prevent flow and possible corrosion behind the liner hanger and in the casing annulus below the hanger. Flow-wetted areas of the liner hanger/packer will be 13 Chrome or similar corrosion-resistant material.

6.3.6 Expandable Sand Screens

Expandable sand screens (ESS) will be used to control potential sand production. The ESS are run into the open hole and expanded by pushing a mandrel through them.

ESS sand control comes from an overlapping filtration medium (weave screen). ESS screens are fabricated from 316L and 25Cr material which is highly corrosion resistant.

The Patricia well is programmed to have a single 450m section of ESS. The geological and reservoir objective of the long reach Baleen well is to connect two potential separate reservoir drainage areas. The current concept is to run screens only over some 450m at the toe and another 450m at the heel of the well. The remainder of the 1,500m open-hole can be covered by blank pipe.

6.3.7 Workovers and Well Intervention

Routine well intervention is not expected through the production life of the field. However each well is designed to allow a well flow test with wireline run downhole gauges and possible PLT logs at the time of completion.

Reservoir monitoring data will be collected with gauges at the production manifold. Completion equipment reliability is expected to be very good given the benign production conditions with a sweet shallow gas field.

All well interventions will require a rig or other suitable vessel to enable sub-sea intervention. A floating drilling rig will perform future workovers.

6.3.8 Drilling and Completion Schedule

Drilling and completion operations are expected to commence in the second quarter 2002. Each well is estimated to take 20-25 days to drill and complete.

The exact timing will be driven by rig availability and the requirement to complete the wells prior to tie-in to the pipeline and umbilical control systems.

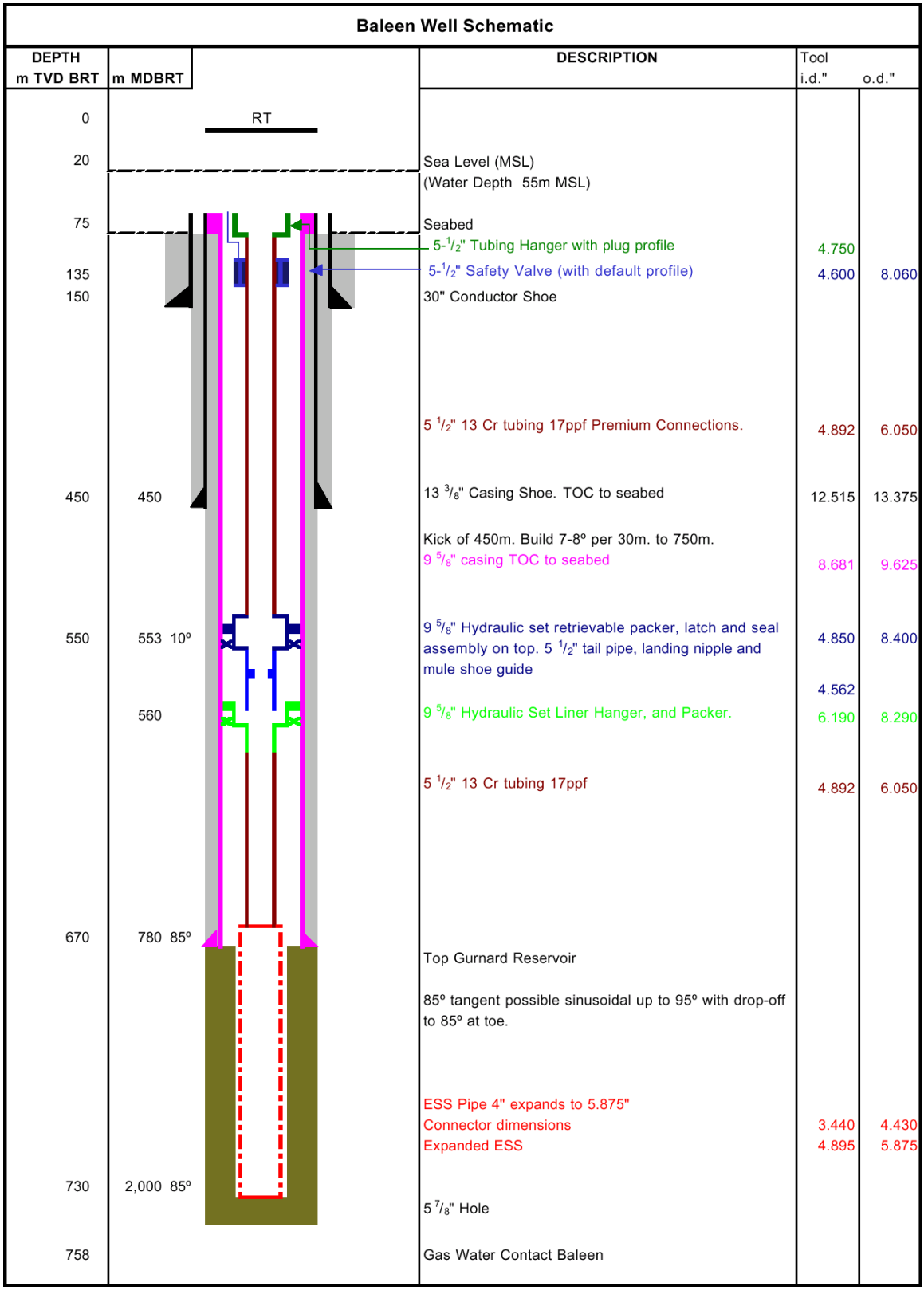

Figure 6.3.8 Baleen Well Schematic

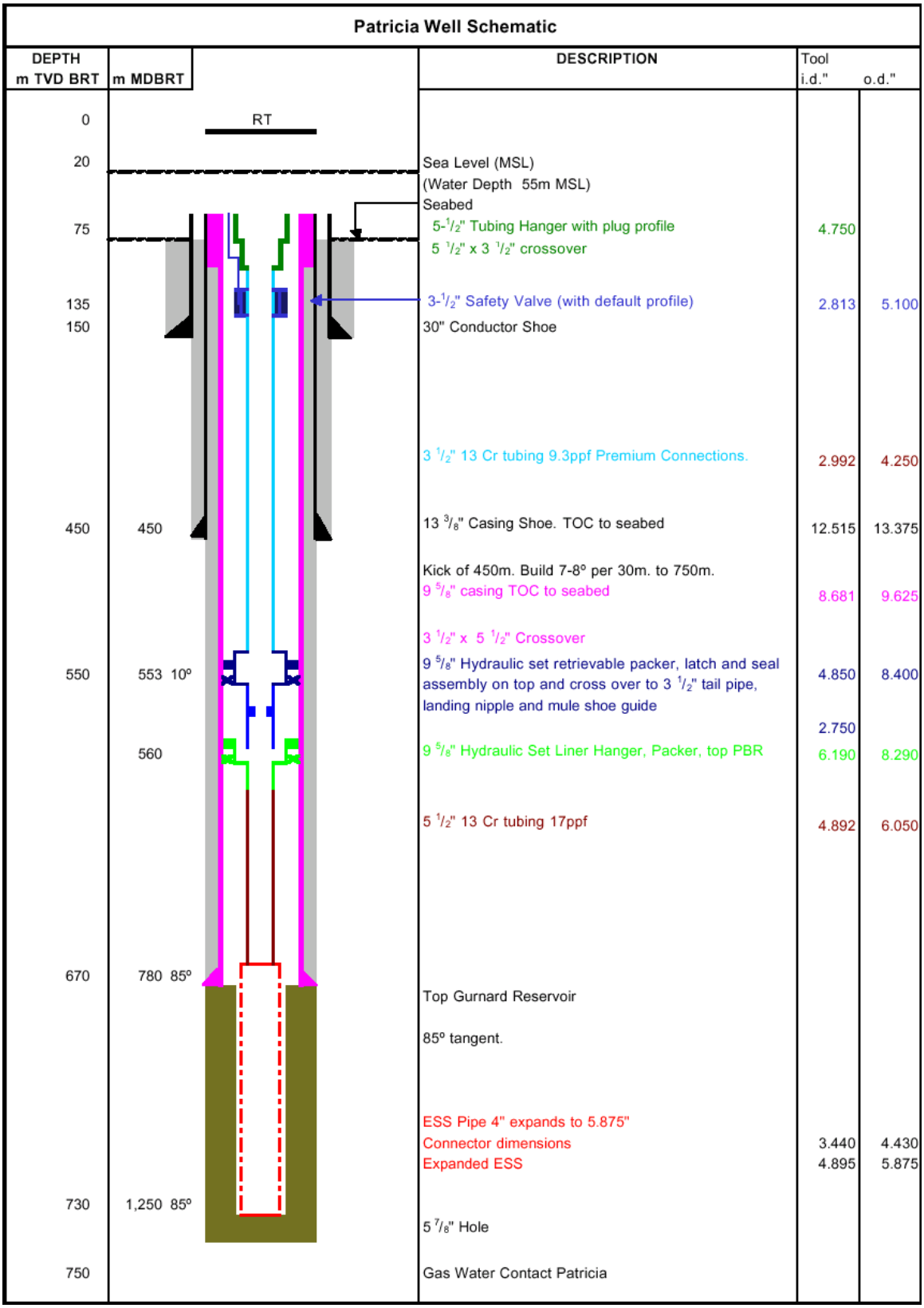

Figure 6.3.8a Patricia Well Schematic

7.0 ENVIRONMENT AND SAFETY

7.1 Introduction: Health, Safety and Environment System

OMV AG has established a number of corporate Guiding Principles, setting out an ideal against which we can measure ourselves, and against which we as a company would like to be measured. One of the Guiding Principles states that: "we are guided in our work by the responsibility for man, the environment, and technical advance".

OMV AG has also established HSE Guidelines to be used for the establishment of HSE management systems in OMV operated ventures. These Guidelines are designed to document OMV principles in health, safety and environment.

OMV Australia has established its own HSE Policy (HSE-00-ZF-001) to implement the corporate HSE Guidelines and in line with local Safety and Environmental legislation. The HSE Policy is in Appendix I.

To implement the HSE Policy OMV Australia has developed a Health, Safety and Environmental Management System (HSEMS). The HSEMS is designed to ensure that the likelihood of people or the environment being adversely affected as a result of OMV Australia's activities is reduced to as low as reasonably practicable.

The HSE components of the system have been documented in the HSE Management System Manual (HSE-00-ZF-002) to facilitate their understanding and implementation and to enable them to be monitored and audited.

The HSE objectives of the Patricia Baleen project team are to incorporate environment and safety into all design activities and construction work, and initiate a positive approach and application to hazard identification with the aim of engineering out potential risk conditions.

OMV will ensure that:

- All potential environmental and safety hazards are identified and assessed.
- Controls are put in place to ensure delivery of the project that will not cause unnecessary harm to the environment.
- Construction and commissioning work is undertaken in a safe and environmentally acceptable manner.
- A system of incident and emergency procedures and contingency plans are initiated for each stage of the project.

OMV will also ensure that all contractors to OMV understand and comply with applicable regulations as well as the conditions imposed by regulatory authorities in approving the commencement of construction and operational activities. Contractors will be audited to ensure that their operations are acceptable and that in carrying out their activities they fulfil the requirements of the project Health, Safety and Environmental Management Plans.

7.2 Environmental Management

OMV is committed to delivering the Patricia-Baleen project to meet the highest environmental standards expected by government and the community.

7.2.1 Environmental Approvals

Early in 2000 OMV Australia commissioned an environmental report to highlight the likely range of environmental risks associated with the project and to facilitate the development of an

environmentally sensitive design. In May 2000 this report *Patricia-Baleen Project Preliminary Environmental Advice* was provided to several Victorian and Commonwealth government departments to assist in the determination of the level of environmental impact assessment required for the project.

At the end of June 2000 the project was designated under the *Commonwealth Environment Protection (Impact of Proposals) Act* and the preparation of a Public Environment Report (PER) was required. In Victoria, the project was designated by the Minister for Planning under the *Environment Effects Act*. The Environment Effects Statement (EES) process is facilitating coordination of approvals under other relevant Acts (e.g. the Planning and Environment Act, Environment Protection Act etc). A combined PER-EES has been prepared and publicly advertised in conjunction with the EPA Works Approval Application and (onshore) Pipeline Permit Application. The PER-EES contains the Strategic Environmental Management System (SEMS) for the project. The SEMS is a controlled document and will be updated once all submissions to the PER-EES have been reviewed and approval conditions received. It will then continue to be reviewed on a regular basis.

The advertising period for the PER-EES was from 17th March 2001 to 20th April 2001.

An Environment Plan for the offshore component of the project will be prepared under the P(SL) (Management of the Environment) Regulations 1999.

7.3 Safety Management

The main philosophy underlying safety planning for the Patricia/Baleen project is the adoption of "safety in design" principles involving the identification and elimination of hazards at the earliest possible stage. In line with this philosophy OMV has defined Safety Goals and Safety Acceptance Criteria (PB-00-SQ-001). The Safety Goals define the objectives, with respect to hazard minimisation and risk reduction, that the performance of an operating facility is measured against. Risk Acceptance Criteria define the level of risk to which an individual or group of individuals may be exposed to, which is either intolerable, broadly acceptable (negligible risk) or tolerable if reduced to as low as reasonably practicable.

The five Safety Goals set by OMV are:

1. To Eliminate or Minimise the Hazards
2. To Prevent Realisation of the Hazard
3. To Prevent Escalation of an Accident Event
4. To Minimise Exposure of Personnel to Hazards
5. To Provide Effective Emergency Response to Any Credible Accident Event

The Risk Acceptance Criteria for the project are:

1. Risk levels to workers may be presented in terms of Individual Risk Per Annum (IRPA). Figure 7.3.1 illustrates the OMV individual risk acceptance criteria for workers. Individual risk levels above 1 x 10^{-3} per year are deemed intolerable and must be reduced, irrespective of cost. Individual risk levels below 10^{-5} per year are broadly acceptable without further study. Risks which lie between 1 x 10^{-3} to 1 x 10^{-5} per year must be reduced to ALARP.

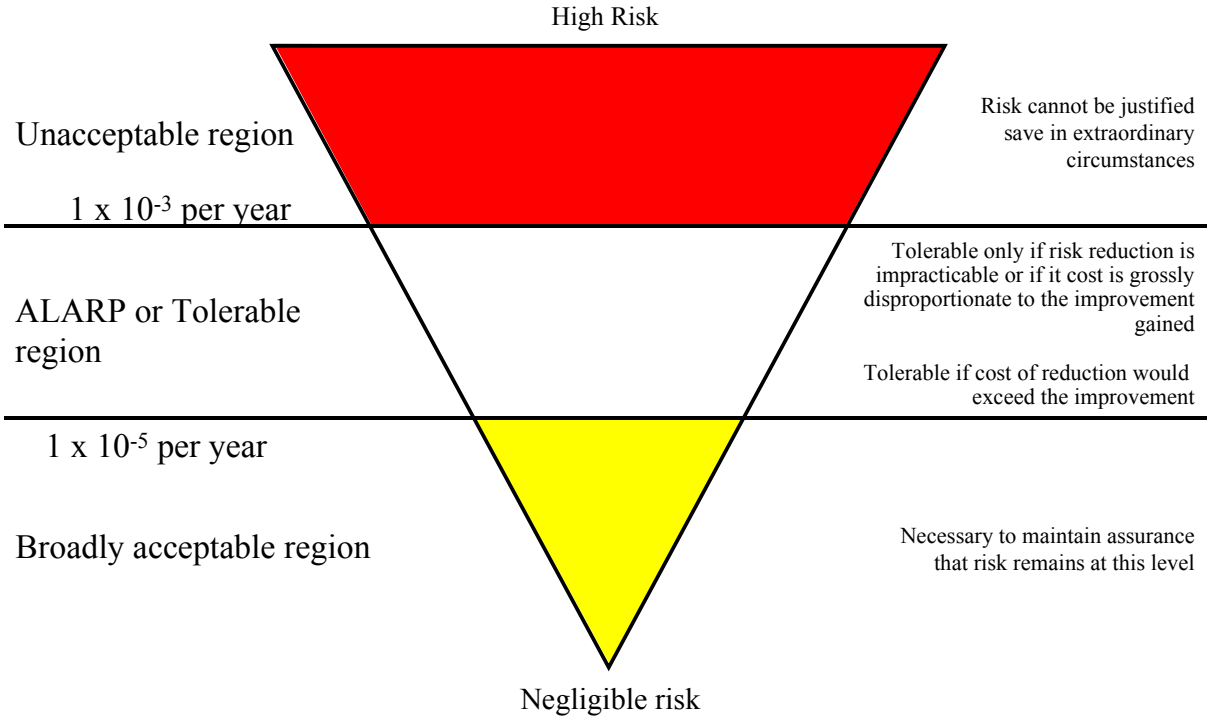

Figure 7.3.1 Individual Risk Per Annum Acceptance Criteria

2. Risk criteria for public safety are in accordance with guidelines provided by the Victorian WorkCover Authority. The applicable criteria for the Patricia/Baleen gas plant are those for new installations and are as follows:

   - The target individual risk of fatality is 10^{-5} per year at the plant boundary;
   - Individual risk of fatality must be below 10^{-7} per year in residential areas.

3. To demonstrate ALARP, additional risk reduction measures, above those already in place, must be identified and their "practicability" assessed.

During the pre-project phase of the development OMV Australia has undertaken a number of safety studies to ensure that the chosen development option meets the stated safety goals. These studies include:

- Comparative Risk Ranking of offshore development options
- Preliminary Hazard Identification Workshops (PB-00-RF-002)
- Onshore Gas Plant Risk Assessment (PB-03-RG-004) (PB-03-RG-001)
- Odourant Injection Facility Buffer Definition (PB-03-RG-003)
- Onshore Gas Plant Comparison of Flare and Vent options

7.3.1 Safety Case

A single Safety Case will be developed for the Patricia/Baleen offshore and onshore facilities in accordance with the Safety Case Plan (PB-00-SQ-002). The objective of having a single Safety Case covering the whole development is to ensure that Safety Case principles are applied uniformly across the project and to provide a single reference document for use by the operator, whilst still satisfying the various legislative requirements.

Adequate time will be allowed for review and approval of the Safety Case and it will be developed with full and open consultation with all relevant parties. The Safety Case and supporting

documentation will be submitted in stages to DNRE. This submission (i.e. section 7) including the onshore (section 5.3) and offshore (section 5.2) facility descriptions, constitutes stage 1 of a proposed 3 stage process. The stage 2 submission will include:

- A more detailed facilities description including the critical operating parameters;
- Aspects of OMV Australia's and the contractors' Safety Management Systems controlling design, construction and installation activity; and
- A formal safety assessment to demonstrate that hazards have been identified and assessed and that the risks are As Low As Reasonably Practicable (ALARP).

It is anticipated that documents will be submitted to DNRE as and when they become available and that issues arising will be discussed and resolved on an ongoing basis. Not withstanding this it is proposed that the formal Stage 2 documentation will be submitted to DNRE approximately 2 months prior to the beginning of offshore construction.

The third stage of the process will be the compilation and submission of the "Operations Safety Case." The Operations Safety Case will comprise:

- Facilities Description (as submitted under Stage 2 and incorporating comments from the DNRE);
- Safety Management System covering operations and maintenance;
- Formal Safety Assessment (as submitted under Stage 2 and incorporating comments from the DNRE).

As for the Stage 2 submission it is proposed that this is an interactive process. However it is proposed that the formal Stage 3 documentation will be submitted to DNRE approximately 1 month prior to the beginning of production operations.

Offshore drilling activities will be conducted under a drilling rig safety case and bridging document.

8.0 PROJECT EXECUTION

8.1 Project Management

The project management approach for the engineering and construction phase of the Patricia-Baleen development is founded on the establishment of a small in-house team of personnel dedicated to the project and supported by other in-house groups (technical, commercial, legal, accounting, etc). Specialists on a part-time basis as required will supplement the team. The alternative to this approach, using an external managing contractor, has not been adopted, as it is not warranted for a simple project of this scale and time frame.

The team will be led by the Development Manager, who is responsible for achievement of the overall project objective, which is to reach start-up within the specified time frame and budget, to the required standards of operational efficiency, quality, safety and environmental care. Senior engineers, each typically having more than 20 years experience, will support the Development Manager and take responsibility for sub-sections of the project such as development drilling, petroleum engineering, engineering and construction of surface facilities, project control, and development of the Safety Case.

The primary role of the project management team is to:

- Consider alternative development schemes, nominate the most appropriate and upon approval, prepare and implement a plan that satisfies the project objectives.
- Coordinate the requirements of all contributing parties, including the Company, contractors, government agencies and the community.
- Identify and manage risks, and foresee and manage events that may threaten the project objectives.
- Provide sufficient flexibility to cater for changes in parameters, but implement change control on the development concept and design bases in accordance with agreed authorities.
- Ensure that information is available when required to those who require it to make timely decisions, give approvals and/or produce critical documentation.
- Avoid duplication of effort in reaching project objectives, but apply sufficient supervision to ensure that contractors meet quality and schedule objectives.
- Monitor and report on costs and progress.
- Ensure that those responsible for operation of the facilities are provided with sufficient information and access to ensure a smooth start-up and safe and efficient continuing operations.

The Project Execution Plan gives a detailed explanation of project milestones and constraints, work breakdown structure, contracting strategy, risk management, regulatory requirements, project controls, quality management, industrial relations and preparation for operations. For reference, a summary of these matters is given below.

8.2 Project Schedule and Constraints

The target date for first gas production is 1 July 2002. The main constraints in achieving this date are:

- Project sanction by July 2001.
- Completion of the environmental approvals process by September 2001.
- Timely delivery of long lead components of the offshore production system.
- Availability of a rig for production drilling in April 2002.

8.3 Contracting Strategy

The Project will be broken down into 3 main sections for contracting purposes as follows:

a) Two development wells.

b) The offshore facilities, comprising a sub-sea production system connected to an offshore pipeline including the shore crossing section. Production will be controlled from an onshore control room via an electro-hydraulic umbilical system.

c) The onshore plant, comprising the inlet separator, compressors, gas dehydration, utilities, controls and metering and the pipelines, comprising the section of wet gas feed line from the start of the shore crossing to the plant, plus the pipeline from the gas plant to the delivery point.

The key philosophies governing the contracting strategy are risk minimisation, cost effectiveness and schedule optimisation and include the following considerations:

- Use of only relevantly experienced, pre-qualified specialist Contractors
- Programming of the work to maximise the use of specialised Contractors already mobilised in the area
- Packaging of the work to minimise interfaces

OMV Australia will act as the managing contractor for the well drilling, awarding and coordinating contracts for the various elements of the work, including the drill rig, support services, logistics, consumables and marine and air transport. Most of these contracts will be reimbursable in nature.

The drilling spread will be used for installation of the Xmas Trees and manifold.

The project pipeline installation is being programmed to be undertaken by an all-weather lay vessel, which will be mobilised in the region for another major pipe lay operation. This offers significant cost and risk minimisation benefits through mobilisation savings and operational capability.

A specialist subsea contractor will be used for installation of the umbilical and control system, pipeline burial and tie-ins.

For the Onshore facilities, a Turn-key EPC contractor will be used to provide a fully commissioned facility warranted to satisfy specified performance requirements.

The General Terms and Conditions of Contract required for the work are the functional responsibility of OMV Australia's commercial manager. These are being developed in conjunction

with legal advice and will be based on tested documentation employed for similar projects in the region.

Contractors will be required to give full and fair opportunity to local industry to participate on an equal basis with overseas companies where the local company can demonstrate satisfactory financial robustness, quality, environmental and safety management systems and the capability to meet the schedule requirements of the project.

Wherever possible, opportunities to reduce costs by sharing mobilisation costs will be pursued. It is noted that other offshore construction work is likely to be in progress late in 2001 and early in 2002.

8.4 Regulatory Requirements

The project will be covered by the laws and regulations of both the Commonwealth and Victorian governments.

During the execution phase, following joint agreement between OMV Australia and government agencies on the development scenario, the main regulatory constraints arise from the requirements of the Petroleum Submerged Lands Act, the conditions attached to environmental approval, and the schedules to the various Pipeline Licences required. Approvals during this phase will be administered by the Victorian Department of Natural Resources and Environment (NRE).

Safety Cases must be prepared and approved for all facilities - Construction Safety Cases prior to commencement of the relevant construction work, and the Operations Safety Case prior to commencement of operations. In addition, validation is required from an independent agency confirming that for each part of the facilities (pipeline, platform, etc) design, manufacture and construction have been in accordance with the relevant codes and standards and that the facility is fit for the intended purpose.

In dealings with government agencies, communication will be directly via OMV Australia, although contractors and external consultants will prepare many of the plans, procedures and other documentation needed to support various applications for approval.

8.5 Quality Management

Project activities associated with engineering and construction of the Patricia-Baleen facilities will comply with the relevant requirements of the ISO quality standards. A quality management system will be implemented based on the following principles:

- The Company management will ensure that personnel understand the quality policy, that authorities and responsibilities are clearly defined, that sufficient resources are available, and that the effectiveness of the system is reviewed at appropriate intervals.
- The process of project management will be designed to ensure that all work proceeds in a controlled manner. The Company management will endeavour to minimise project scope changes, but where changes are necessary will adopt an agreed charge control procedure.
- Contracts will only be awarded to organisations capable of meeting contractual requirements. The responsibilities of contractors and suppliers will be clearly defined and any differences from tender requirements will be resolved prior to contract award. Contractors will be required to maintain effective quality management systems.
- The design, manufacture and construction of all major elements of the project will be verified by suitably qualified independent third party organisations.

- All project documents will be subject to control, both within the Company and within contractor organisations. Obsolete documents will be promptly removed from use, and a system established to ensure that all parties are working to the latest revisions.
- Safety-critical materials and equipment will be identifiable and traceable from applicable drawings and specifications during all stages of production, delivery and installation.

8.6 Industrial Relations

In all construction contracts the Contractor will take responsibility for industrial relations with its own workforce and will not be compensated for any costs or lost time arising from industrial action, except when the cause was external and beyond the Contractor's control. However, to avoid disruption of the project the Company will apply the following guidelines:

- Contractors' track record in industrial relations will be considered as part of the evaluation of bids.
- Major contractors will be encouraged to maintain membership of one of the recognised industry associations. Rates of pay and other working conditions should follow existing precedents wherever possible.
- The workforces of different contractors will be separated as far as practicable, to avoid disputes arising from differences in working conditions, and to avoid contractors being able to attribute their own problems to other contractors and thus to the Company.
- Contractors will be required to maintain effective safety policies and procedures so that safety disputes do not arise.

8.7 Cost Control and Forecasting

A cost control system will be established to develop a realistic project estimate as a basis for approval of the project budget and Authorisations for Expenditure (AFEs).

- Track commitments against budget elements to provide an ongoing forecast of completion costs.
- Accommodate, record and manage any project scope changes.
- Forecast cash flows for administration of cash calls to enable timely payments.
- Enable allocation of costs against assets.
- Provide audit ability of records and cost data.
- Control of variation claims.

8.8 Planning and Scheduling

The objectives of the planning and scheduling system are to:

- Provide a realistic project schedule for setting timely performance goals.
- Define and schedule major project approvals that can constrain the first gas date.
- Identify and report physical progress (overall 'S' curve and critical path).
- Identify suitable weather windows for the project.
- Control contractors' claims for extensions of time and variations
- Provide flexibility in accommodating project scope changes.

9.0 OPERATIONS AND MAINTENANCE (O&M)

The plan for operating and maintaining the facilities is integral to a successful development. The O&M approach has a large influence upon the design of the facilities requirements and yearly operating costs.

9.1 Operations and Maintenance Approach

The intent is to implement an operations and maintenance (O&M) program which ensures safe, reliable and cost effective operations. The contractor will provide sufficient resources and staff within the organisation to perform most of the normal day-to-day needs of the operation initially. The contractor will be committed to recruiting and training local personnel for ongoing operations and maintenance of the facilities. For peak requirements, such as campaign maintenance programs, these resources can be supplemented from the O&M contractor's national resource pool on an as needed basis. For highly specialised procedures such as pigging, drilling or well intervention activities specialist contactors will be utilised as required.

The strategy for the development of the onshore facilities is as follows:

- Alternative strategies are being considered for the development of the onshore facilities. Strategies under review include a supply and maintenance contract for the provision of leased compression with the balance of plant completed under an EPC style contract. Alternatively, EPC may be considered for the entire onshore scope. The most appropriate contract strategy will be selected after a full technical and economic review.
- A service contract for the supply of operating and maintenance services shall be entered into with a contractor that is recognised as having a track record in the operations and maintenance of both onshore and offshore hydrocarbon facilities.

The O&M contractor shall manage the day to day operations and maintenance activities of both the onshore gas processing, the onshore pipelines and the offshore pipeline. The contractor shall be responsible for the operations and maintenance of the subsea production facilities with the exception of activities requiring well intervention or drilling. All maintenance associated with the subsea wells will be managed by OMV Australia. The gas metering facility may be operated and maintained by either OMV Australia or Duke energy International.

A suitable contractor, with a pool of personnel experienced in offshore and onshore gas production operations will be selected at an appropriate stage in the development schedule to ensure that adequate training and familiarisation is achieved prior to start up of the offshore facilities and the onshore plant. This approach allows the following:

- Initial start up and operation of the facilities with experienced O&M personnel;
- Gradual phase in of local personnel as they gain training and experience to fill all operating positions and
- Access to the experienced O&M personnel for high demand maintenance or repair periods.

OMV Australia will maintain ongoing support for reservoir, geology and future technical support in the most cost effective manner.

Maintenance will be carried out on a campaign basis, at planned intervals, using experienced contract O&M personnel. Inspection of pressure vessels and recertification of safety valves will be included in the planned maintenance activities. The sales gas compressors are anticipated to require the most maintenance effort. These will be serviced in accordance with the manufacturers recommendations.

The original concept for development of the onshore facilities was to award a BOO (Build, Own, Operate) contract for the onshore plant. The BOO contract would encompass the design, procure and construction of the onshore plant and the operating and maintenance of both the onshore and offshore facilities with the exception of well intervention activities.

After evaluation of the BOO submissions by short listed contractors it became evident that the BOO concept was not going to provide the best model economically for a project of this size. A review of alternative contracting strategies concluded that an EPC type of contract, with OMV retaining ownership of the asset, would provide the most optimum arrangement. OMV Australia is continuing to investigate options for leasing major equipment items to more closely match installed plant with the projected production profile. Under this strategy OMV will subcontract the day-to-day operations and maintenance activities to an O&M service provider.

9.2 Onshore plant

The predominant activities are centred on the day-to-day operations and maintenance of the facilities. The following functions are envisaged:

- Onshore plant operation and maintenance
- Pipeline operation, maintenance and pigging as required
- Pipeline repair response
- Gas sales metering
- Co-ordination of all offshore activities (when they occur)
- Facilities routine and predictive maintenance
- Facilities repair
- Co-ordination of vendors to support warranty maintenance as required
- Date gathering
- Sales gas quality monitoring
- Safety and environmental management.

Onshore operations will be responsible for logistics management including co-ordination of all maintenance activities, control of operational and maintenance spares, warehousing, procurement and so forth.

The onshore operator shall be committed to supporting a sound safety, health and environmental approach to work and providing ongoing training for all operational activities. Continuous monitoring of safety and environmental performance shall be a key performance indicator in the ongoing management of the facilities.

The manning requirements for the onshore facilities will be determined and agreed in consultation with the O&M contractor. At this stage it is anticipated that for the first two years, two people will man the plant 24 hours a day, seven days a week on a 12 hour back to back shift basis, with the ability to call out additional maintenance resources from Sale or Melbourne as required. For the remainder of field life, and assessed on the operating experience of the first two years, the plant will not be manned at night but cover will be available on a call out system from operators stationed in the nearby town of Orbost.

9.3 Offshore Facilities

The offshore facilities consist of two wells completed subsea and tied-back to a manifold upstream of the subsea pipeline. The subsurface valves and the choke valves will be controlled from shore via an umbilical line which provides power and hydraulics to the offshore facilities. Injection of chemicals such a corrosion and hydrate inhibitors shall also be managed from shore via the umbilical.

A VDU, located in the onshore control room next to the onshore display panel, will allow convenient operation of the offshore facilities by the onshore operators. It is unlikely that additional resources will be required routinely to operate and maintain the offshore subsea pipeline and facilities. The predominant day-to-day activities will be centred on:

- Control of the offshore wells via an umbilical containing the power, hydraulic and signal cables
- Adjustment of the choke valves via position indicators
- Corrosion inhibitor injection either into each well stream or into the pipeline inlet
- Infrequent injection of hydrate inhibitor
- Maintenance of the chemical injection skid and the hydraulic and electric power unit located at the onshore facility
- Pipeline operation
- Pipeline maintenance and pigging as required
- Co-ordination of pipeline repair response
- Yearly inspections of subsea pipeline via ROV
- Data gathering

Any operation or maintenance activity requiring 'well' intervention, including workovers and drilling will be managed by OMV.

The head office, based in Perth, will co-ordinate, manage and execute all well intervention activities through its fulltime Drilling Manager and team of specialised staff. Where required external resources will be contracted in to assist in design, construction or job execution programs as required.

9.4 Maintenance and Spares Approach

After the detailed design of all the facilities has been completed, a review will be initiated in consultation with equipment vendors, to better define the requirements for spares holdings. The approach is defined as follows:

- All routine maintenance or frequently used items are to be made available at short notice from direct spares holdings, or from equipment suppliers;
- For critical equipment that can be repaired or replaced in three to four hours, keep spares in stock;
- For critical equipment with backup that requires vendor representatives for repair or replacement, arrange for 24 hour delivery repair contracts;
- Spares for offshore equipment shall be held at the onshore plant or vendors as per the above criteria
- Ensure worker skills are available.

In addition to arrangements with suppliers regarding spares holdings, arrangements will be put in place to achieve rapid delivery of spares and materials from a strategically located depot in the Melbourne area. This system provides very rapid availability of critical items to the operation.

APPENDIX A GOVERNMENT COMMUNICATION

Appendix A gives an overview of the various communications held with the DNRE since the submission of the Patricia-Baleen Proposed Development Concept (PDC) in July 2000.

2001 (April)	Official correspondence (letter is attached) from DNRE representing the joint technical paper based on the PDC. *This letter was prepared by the DNRE in August 2000 and formally received by OMV in April 2001. However these comments were addressed by OMV in technical discussions with DNRE and DISR/AGSO held in September 2000. A copy of the relevant minutes and various communications are given in Appendix A.*
2000 (November)	Correspondence (E-mail attached) sent by OMV to DNRE on the impact of the regional aquifer as a result of gas production from Patricia-Baleen reservoirs.
2000 (September)	DNRE comments on the minutes (E-mail is attached). *A hardcopy of the presentations (see below) made to the DNRE and the draft Reservoir Management Philosophy provided to the DNRE are included in the Appendix.* *Presentations:* ▪ Patricia/Baleen 13th September 2000, Presentation to Joint Authority ▪ Patricia Baleen Drilling and Completions Summary
2000 (September)	Meeting held with DNRE (minutes are attached) on 13/9/00.
2000 (July)	PDC submitted.

Department of
Natural Resources and Environment

240 Victoria Parade
PO Box 500 East Melbourne
Victoria 3002 Australia
Telephone: (03) 9412 4011
Facsimile: (03) 9412 4803
ABN 90 719 052 204
DX 210099

18 April 2001
Our Ref: PE/17/0503

Ms Janet Hahn
Development Manager
OMV Australia
44 St Georges Terrace
Perth 6000
WESTERN AUSTRALIA

FAXED 18/04/01

Dear Ms Hahn;

PATRICIA BALEEN DEVELOPMENT VIC/RL5
DEVELOPMENT CONCEPT JOINT TECHNICAL PAPER

I have attached a copy of a letter, dated 18 August last year, sent from this Department to the Department of Industry, Science and Resources (DISR) in Canberra which summarises our technical comments on the OMV Patricia Baleen Proposed Development Concept document as submitted on 18 July 2000. We have not received any additional technical comment from the DISR relating to this project.

Although we are aware that your development planning has firmed up and changed in a number of areas, I am now forwarding the document to you - as it may prove helpful to your staff when preparing the Development Plan in support of any application for a Production Licence.

23 APR 2001

Yours sincerely;

HORACIO HAAG
Manager Petroleum Operations, Safety and Environment

Victoria
The Place To Be

For further information about NRE contact the Customer Service Centre on 136 186 or visit our website at www.nre.vic.gov.au

FAXED 21/8/00

Natural Resources and Environment
AGRICULTURE
RESOURCES
CONSERVATION
LAND MANAGEMENT

18 August 2000

Paul Kay
Petroleum Exploration and Development Branch
Petroleum Division
Department of Industry, Science and Resources.
GPO Box 9839
CANBERRA ACT 2601

Dear Mr Kay

VIC/RL5 PATRICIA BALEEN DEVELOPMENT CONCEPT.
OMV AUSTRALIA PTY LTD.
JOINT TECHNICAL PAPER.

Officers of this Department have reviewed the Patricia Baleen Proposed Development Concept as submitted by OMV Australia Pty Ltd on 18 July 2000. A copy of this document was sent to John Kjar directly by the proponent on that date.

The document is intended as an outline of the Field Development Plan, which OMV will submit in Q4/2000, in support of an application for the grant of a production licence.

At the time of this Development Concept submittal OMV were still processing 3D seismic acquired earlier this year, had not firmly decided on the number of development wells or their target reservoirs, and had not made a selection between offshore platform and sub-sea completion options. The plateau production rate and duration depended on whether the gas sales contract would be a depletion or a supply type contract. The concept development plan as submitted is supported but there are too many unresolved issues for it to be evaluated as a preliminary development plan. It is therefore my opinion that it would not be useful for this Department to prepare a draft of a "Joint Technical Paper" at this stage.

The purpose of this letter then is to list, for your information and concurrence, the issues which have been distilled from a review of the document, and from subsequent discussions with the proponent, that need to be addressed in the final Field Development Plan. In order to expedite the process and given the short Development Schedule envisaged, we plan to invite OMV technical staff to these offices for a presentation and discussion of the issues in early September.

1

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Telephone: (03) 9412 4011 Facsimile: (03) 9412 4803

Victoria
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Technical Issues.

1. Scope

The fields ultimate recovery is estimated by OMV to be 77 Bscf of sweet dry gas (97% Methane). Production facilities comprising dehydration, compression and metering for 75 MMscf/d are to be installed such that the gas can be sold into the onshore Eastern Gas Pipeline some 30 Km East of the field. A production life of around 7 years is foreseen.

Previous operators Lasmo, Shell and Cultus have all tried to commercialise the field since its discovery in 1981, but were frustrated by gas marketing and infrastructure problems.

2. Adequacy of Efforts to Understand Geology of Licence Area.

No plan to manage the many remaining uncertainties has been included, but OMV have stated that this will form part of the final Development Plan.

The premise that the predicted ultimate recovery can be produced through a minimum number of wells may be frustrated by reservoir compartmentalisation. This can only be judged when the 3D seismic is available. We will encourage OMV to update the Eclipse model to incorporate the 3D seismic, the Baleen-2 results and the well selections before the final Development Plan is submitted.

3. Alternative Options for Optimising Development of Petroleum.

The sub-sea completion option has now been selected by OMV and a contract has been awarded to a Clough/Worley joint venture. We also understand that there will be only two firm wells in the first phase of development. It is not clear if these will be vertical or deviated wells or what portions of the reservoir they will target. This needs to be discussed with OMV in the context of the 3D seismic evaluation and the plateau production rate of the sales gas contract.

The selection of the sub-sea option means that future well intervention will require a Mobile Offshore Drilling Unit (MODU) or other suitable vessel, although permanent downhole guages will be installed for reservoir monitoring purposes.

The ultimate recovery of Patricia Baleen will depend on the abandonment pressure and therefore upon the optimisation of the plant inlet pressure, plant location and offshore pipeline diameter. These parameters have yet to fixed by the proponent.

4. Flexibility to Enable Development of Additional Reserves.

The Patricia/Baleen field will be the first gas production from the Gippsland Basin that is not operated by Esso Australia Limited. The production facilities will be entirely independent from existing Esso infrastructure.

Given the very short production life of Patricia Baleen, the economics of the project depend heavily on the future use of the facilities for transporting and processing third party gas from nearby fields such as Kipper and perhaps from future discoveries in VIC/P19.

It is also possible that the Patricia/Baleen field together with its development wells and offshore pipeline could be used for the CO2 injection needed to limit emissions from processing facilities for some of these future developments.

Although no H2S has been detected in the Patricia/Baleen Gurnard formation gas the offshore pipelines and the gas plant inlet facilities are being designed for sour service in order to provide full flexibility for future use.

A tie in for future third party gas production is to be incorporated in the offshore facilities, and the single train onshore plant is to be laid out in a way to facilitate future expansion.

5. Technical Risks.

The biggest technical risk to the project would be a downward revision of the Gross Rock Volume (GRV) as a result of interpretation of the 3D seismic data.

A further risk would be more rapid well productivity decline and a higher abandonment reservoir pressure as a result of water coning. A partial pressure seal against the underlying Latrobe group clastics is interpreted by OMV, leading them to conclude that bottom water drive will be negligible. This is however difficult to reconcile with their observations of declining Gurnard reservoir pressure as a result of Latrobe Group Aquifer depletion. Whilst the 50mD permeabilty of the Gurnard formation argues against a strong water influx the 3D seismic may indicate the presence of fractures, perhaps connecting the Latrobe directly to the Gurnard.

The adoption of the sub-sea option will make it more difficult to identify and shut-off the source of water production.

6. Environment Plan.

After review of the "Preliminary Environmental Advice" submitted by OMV in May 2000, the project was designated under the Commonwealth Environmental Protection (Impact of Proposals) Act and the Victorian Environmental Effects Act. A coordinated approach is being adopted, and the consultation process with the Orbost Community and the Agencies involved has begun. The scope definition document for the Environmental Effects Statement (EES) is expected to be finalised in the week of 21 August.

Aside from matters relating to pipeline route selection, the following issues will need to be addressed in the EES;

6.1 Declining Water Table in East Gippsland.

There is concern that the observed decline in the level of the onshore water table has been caused by, or exacerbated by, offshore petroleum production, possibly gas from the older and nearer shore fields (Barracouta, Snapper and Marlin). This is an issue for the entire basin, not just for the Patricia/Baleen development, but will need to be addressed in the EES.

6.2 Produced/Condensed Water Disposal.

The Patricia – 1 well has a CO2 content of 1.28 mol %, leading to the possibility of offshore pipeline corrosion at the expected initial upstream pressure. For this reason it is planned to include facilities for the offshore injection of corrosion inhibitors. The plans for disposing of water containing this inhibitor, small quantities of condensate and possibly methanol to an evaporation pond as described in the Development Concept proposal of OMV may not be acceptable. Consideration of the effects of storm water and the possible increase in produced water volumes due to water coning could result in the need for an API separator and a corrugated plate interceptor to ensure that prescribed disposal water standards are met.

6.3 Gas Venting.

According to the OMV development concept a permanently lit flare is not proposed. The acceptability of this arrangement needs to be reviewed after considering emergency blowdown situations, the risk of bushfires and lightning strikes, the fact that gases containing H2S may be introduced into the plant in future and the potential for petroleum/mercaptan fumes from a vent.

6.4 Beach Crossing

The planned horizontal drill under the sand dune and beach also goes under Corringle Creek and there is risk of bentonite mud breaching up into the creek.

6.5 Disposal of Hydro Test Water

The test water will contain inhibitors, biocides and oxygen scavengers. Ideally it should be disposed of offshore, but the commissioning process may favour de-watering the line from the offshore end. If this is the case the onshore disposal of the test water may require that it be trucked away.

6.6 Noise

The continuous operation of the gas export compressors and the distance from adjacent houses is an identified issue and contours will be generated before the plant location is fixed.

7. Safety Plan.

7.1 Safety Cases

Although only the wells and the half of the offshore pipeline fall under the safety case regime of the P(SL)A we have requested, and OMV have agreed to make, a single safety case for the entire integrated project as well as a separate case for the MODU (with bridging document). The integrated safety case would be submitted prior to construction and revised prior to the commencement of operations.

7.2 Diving

The adoption of the sub-sea option removes substantial transportation risks over the life of the facility, but does introduce diving risks during construction. The water depth is 55 meter. The Clough/Worley joint venture plan to use saturation diving with a bell, and this will also be necessary for any future maintenance or well intervention. The tie from the beach crossing to the offshore pipeline is in some 20 meter of water and will require a minimum amount of surface orientated air line diving. It is not time critical and can be undertaken under favourable weather conditions.

7.3 BOO Contractor

The onshore plant and sales gas pipeline will be the subject of a Build, Own, Operate (BOO) contract and this contractor will be additionally responsible for the operation of the offshore facilities. The Safety case will need to be prepared in part by this contractor and will need to set out the means by which OMV will be able to ensure safe operation.

7.1 Avoidance Area and Exclusion Zone

The field lies outside the Gippsland basin avoidance area. A 500 meter exclusion zone around the wells will be granted but will be difficult to enforce. The possibility of fishermen trawling over the well heads, pipeline and umbilical cable needs to be addressed in the safety case.

8. Issues To be addressed in Development Plan.

The final Development Plan needs to reflect the 3D seismic interpretation and should ideally be based on an updated Eclipse model to demonstrate the wells that are planned can produce the projected ultimate recovery. The production forecasts should also reflect the terms and conditions of the sales gas contract(s)

A complete description of the drilling program including well trajectories, perforation intervals, completion designs and testing program is required. We will also require details of the proposed permanent downhole guages.

In order to assess the commerciality of other small gas accumulations that may be discovered in adjacent acreage we would wish to see a calculation of the pre tax / royalty unit technical cost for the development and the discounted cash flow analysis on which it is based.

9. Regulatory Approvals.

So as to be consistent, DNRE will require the same regime of approvals as was applied to the the Blackback sub-sea completion project of Esso in 1998, that is;

9.1 General
- Production Licence and Consent to recover Petroleum.

9.2 Integrated project.
- Safety case.

9.3 Pipeline
- Pipeline Licence and Consent to Operate.

9.4 **Drilling.**
- MODU safety case, bridging document with integrated project safety case, approval to drill.

9.5 Sub-Sea.
- validation of design and manufacture, consent to construct and install, consent to use.

I would appreciate your confirmation that you agree with the approach to the project that I have outlined here, and your notification of any additional technical issues that you consider to have not been fully covered.

Please also let me know if you or any of your staff would wish to attend the proposed presentation by OMV geologists and reservoir engineers in early September.

Yours sincerely

HORACIO HAAG
Manager, Minerals and Petroleum Regulation

6

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ABN 94 082 932 027

Ref No: PB-2041

16 November 2000

Manager Petroleum Resources
Natural Resources and Environment
7th Floor, 250 Victoria Parade
East Melbourne Vic 3002

Dear Dr Mehin,

Firstly, I thank you and your staff for allowing OMV to present the Patricia Baleen project to you in your Melbourne office on 13 September 2000.

At our meeting we had promised to conduct calculations to estimate the impact on the regional aquifer as a result of gas production from the Patricia Baleen reservoirs. Based on our estimations we conclude the following:

- Gas withdrawal (minimal water withdrawal) from the Patricia Baleen Field will have a total estimated maximum impact of 0.15m reduction in aquifer head assuming 100 psi pressure drop in the regional aquifer

- In all likelihood, Patricia Baleen will experience minimal aquifer support and higher pressure depletion accounting for less than 0.15m reduction in the regional aquifer head

- The maximum total impact of 0.15m compares to the current reported estimated 1m annual reduction in aquifer head resulting from Oil, gas & water withdrawals from the Bass Strait fields, the Latrobe Valley Coal Fields & Irrigation water

- Withdrawal from Patricia Baleen will account for only ~1% of combined withdrawal volumes from the Gippsland Basin and the Latrobe Valley to the end of June 1999

We have attached a presentation summarising the approach we have used in estimating the impact of Patricia Baleen production which we consider to be relatively small. Please do not hesitate to contact either myself (08 9223 5023) or Fayaz Jamal (08 9223 5021) if you would like us to clarify any of the presented material or carry out any further analysis.

Yours sincerely

Janet Hann
Development Manager

OMV Australia Pty Ltd

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cc Bruce Armour
Petroleum Operations Inspector
Natural Resource and Environment
Level 8, 250 Victoria Street
PO Box 500East Melbourne, Vic 3002

Vel Vuckovic
Senior Petroleum Engineer
Australian Geological Survey Organisation
GPO Box 378, Canberra ACT 2601

Uma Malipatil
Project Officer - Petroleum
Natural Resource and Environment
Level 8, 250 Victoria Street
PO Box 500 East Melbourne, Vic 3002

Bronwyn Ridgway
Associate Director - Environmental
Maunsell McIntyre
Level 9, 161 Collins Street
Melbourne Vic 3000

-----Original Message-----
From: Bruce.Armour@nre.vic.gov.au [mailto:Bruce.Armour@nre.vic.gov.au]
Sent: Thursday, 28 September 2000 13:32
To: Fayaz Jamal
Cc: Janet Hann; melbmr@dames.com; Geoff.Collins@nre.vic.gov.au; Kourosh.Mehin@nre.vic.gov.au
Subject: Patricia Baleen Impact on Regional Aquifer Pressure

Fayez;

With reference to our meeting on 13 September and your note on the action items
which arose.

Unfortunately Kourosh Mehin is currently on leave, so our response to action
item 3 on the above topic is not as quick and accurate as would otherwise be the
case.

The cumulative total amount of water produced from Gippsland basin oil and gas
wells is about 2 Billion barrels. To this would have to be added the cumulative
oil and gas production volumes at reservoir conditions. We understand that the
amount of water produced annually from the Latrobe Valley coal fields (from
about the same time as the offshore oil and gas production commenced) is around
one quarter of the fluid volumes produced annually from the oil and gas fields.
Annual water production from irrigation bores is about 5% of the fluid volumes
produced from the oil and gas fields.

Some figures might also be available from the presentation on the subject made
earlier this year by Sinclair Knight Mertz. Bronwyn Ridgway will have a copy of
this.

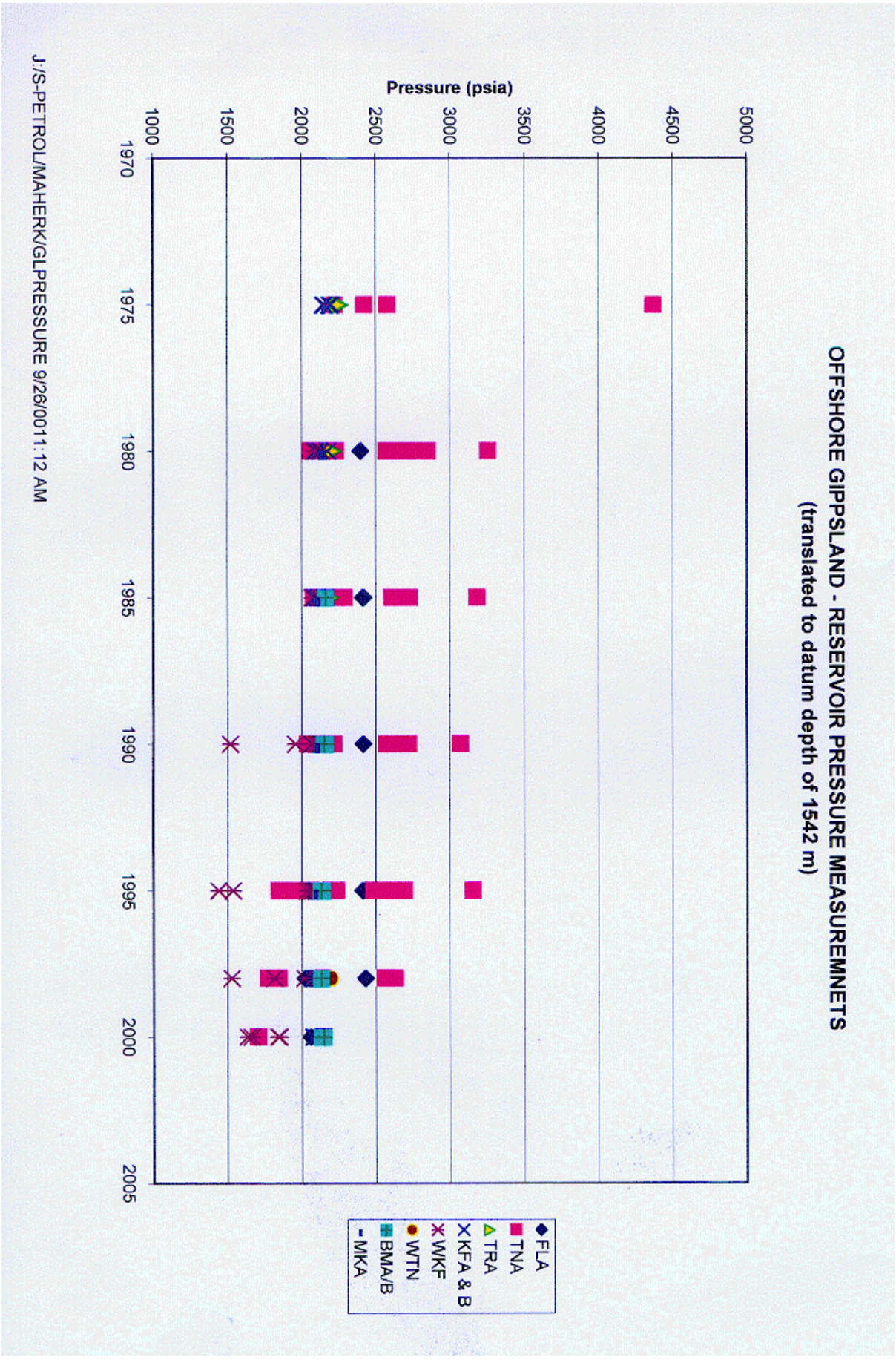
For what it is worth I have also attached a plot, in tif format file, of
reservoir pressure readings over time in selected Gippsland basin oil fields,
adjusted to a datum depth.

I hope that this is useful.

Regards;

Bruce Armour.

(See attached file: Water.tif)


OFFSHORE GIPPSLAND - RESERVOIR PRESSURE MEASUREMNETS
(translated to datum depth of 1542 m)
Pressure (psia)
1000
1500
2000
2500
3000
3500
4000
4500
5000
1970
1975
1980
1985
1990
1995
2000
2005
FLA
TNA
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WKF
VTN
BMA/B
MKA
J:/S-PETROL/MAHERK/GLPRESSURE 9/26/0011:12 AM

-----Original Message-----
From: Fayaz Jamal
Sent: Monday, 25 September 2000 16:41
To: 'kourosh.mehin@nre.vic.gov.au'; 'Bruce.Armour@nre.vic.gov.au'; 'Vel.Vuckovic@agso.gov.au'
Cc: Janet Hann
Subject: Patricia Baleen Sub-surface Presentation

Dear Dr. Mehin, Mr. Armour & Mr. Vuckovic,

further to our meeting of 13/09/00;

Action Item 1 --Copies of Presentation

Attached please find a copy of our presentation and draft of the proposed Reservoir Management Plan. Please note that the Reservoir Management document in a draft copy which is presently being reviewed internally.

Patricia Baleen Drilling Compl...

PatBaleen Sub-surface DNRE.ppt...

Patricia Baleen Reservoir Mgt ...

Action Item 2 -- rw

An initial static rw of 0.542 ohm-m @ 44.9 C was used for the log analysis. This was based on using the Latrobe water salinity which was assumed to be similar to that of the water salinity of the Gurnard Formation based on the very similar measured water pressure gradients in the two formations. Please note though that Sw's were based on capillary pressure curves and not log analysis.

Action Item 3 -- P/B production impact on regional aquifer pressure

The impact on regional aquifer as a result of approximately 60 BCF of gas & 200k BBL of water withdrawal will be calculated and provided to NRE as soon as available.

Patricia Baleen potential withdrawal of 0.06 Tcf of gas (148 million Res Barrels) and approximately 0.2 MMBBL water will be compared to the 5 Tcf of gas and 3,500 million barrels of liquid hydrocarbons + produced water withdrawn from the Gippsland Basin to the end of June 1999.

Dr. Mehin, would it be possible to

- get an estimate of water withdrawn from the Gippsland Basin to end of June 1999 &
- approximate range of pressure drop in regional aquifer ?

Thank you all for your hospitality during our recent visit to your offices.

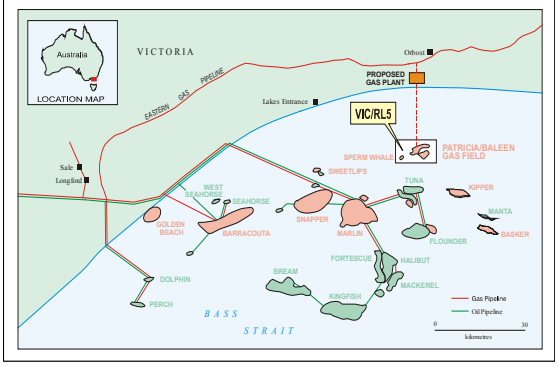
Sincerely,

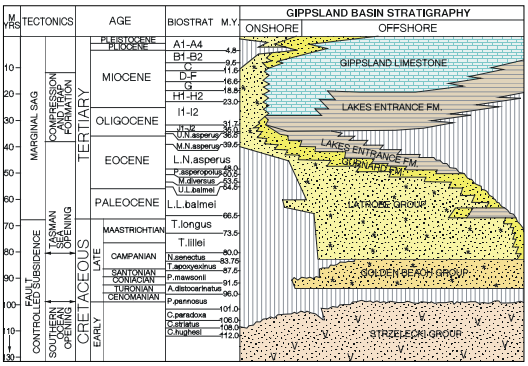
Janet Hann & Fayaz Jamal

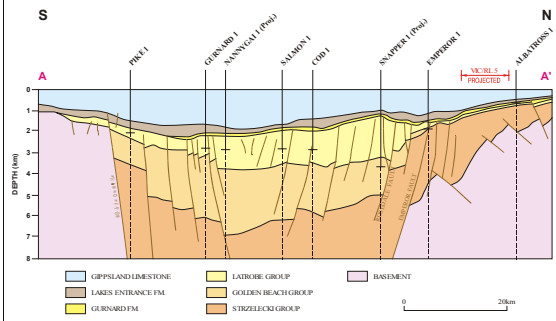
Patricia / Baleen

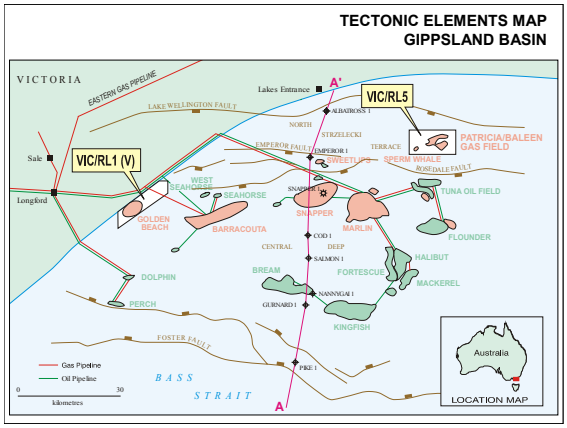
13th September 2000
Presentation to Joint Authority

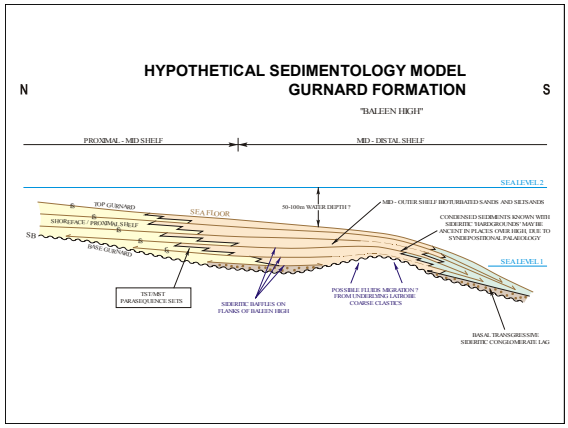
Patricia / Baleen





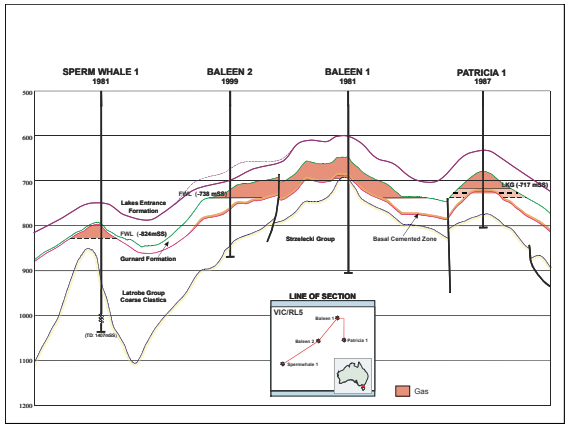






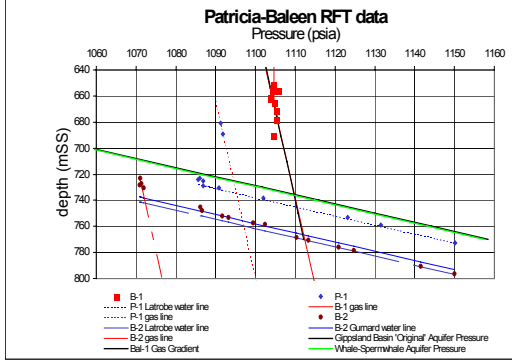
Well Results

Flathead-1	1969	Gurnard Gas Shows, Latrobe Oil Shows
Sperm Whale-1	1981	Latrobe Gas
Baleen-1	1981	Gurnard & Latrobe Gas
Whale-1	1981	Water Wet
Patricia-1	1987	Gurnard & Latrobe Gas
Baleen-2	1999	Gurnard Gas (No Test)

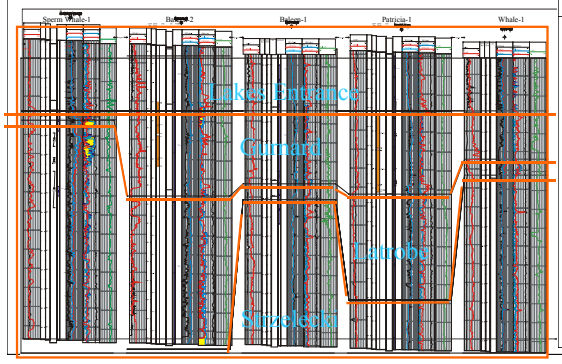


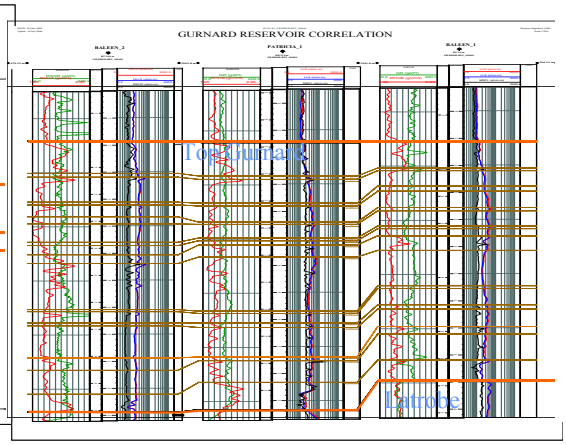
Drill Stem Test Results

- Latrobe Group
  - Flathead-1 (6.7m) Tight
  - Baleen-1 (6m) 1.8 Mscfd
  - Patricia-1 (3m) 2.6 Mscfd
  - Sperm Whale-1 (7m) 5.4 Mscfd
- Gurnard Formation
  - Baleen-1 (8m) 6.35 Mscfd
  - Patricia-1 (35m) 23-25 Mscfd
- Dry Gas 98% Methane



STRATIGRAPHIC CROSS-SECTION

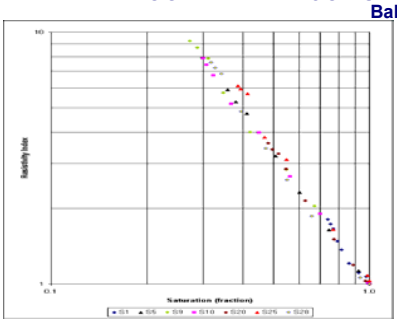




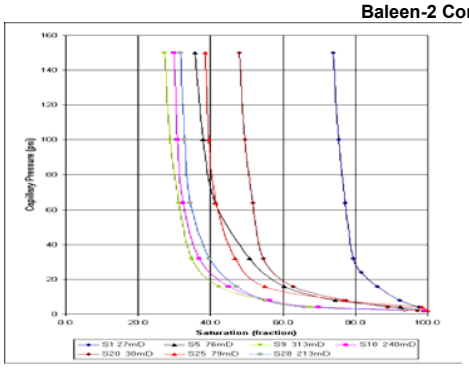
SCAL PROGRAMME
Baleen-2 Core

- Rock Strength and Physical Properties
  - CT Scan
  - Sieve Analysis
  - Uniaxial/Triaxial Compressive Strength
- Petrophysics
  - Capillary Pressure
  - Resistivity
  - Formation Factor
  - Petrography, SEM, XRD
  - CEC
  - Water Floods, Drainage and Imbibition

RESISTIVITY INDEX vs SATURATION
Baleen 2



CAPILLARY PRESSURE CURVES
Baleen-2 Core



Petrophysical Study
Objectives

- Ø, N/G (Sg)
- Provide average layer inputs for simulation

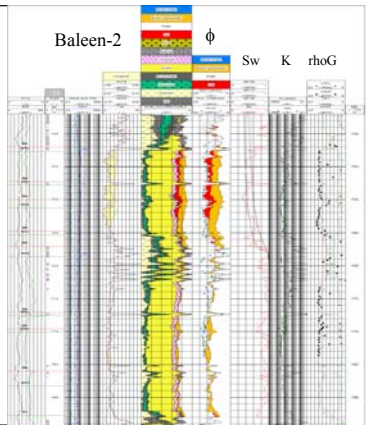
Petrophysical Study

- Wells : Patricia-1, Baleen-1 and Baleen-2
- 2 models used
  - complex at Baleen-2
  - lumped at Baleen-1, Patricia-1
- Lumped model run at Baleen-2 as QC
- Provides input of layer property
- Understanding gained at Baleen-2 used for Baleen-1 & Patricia-1

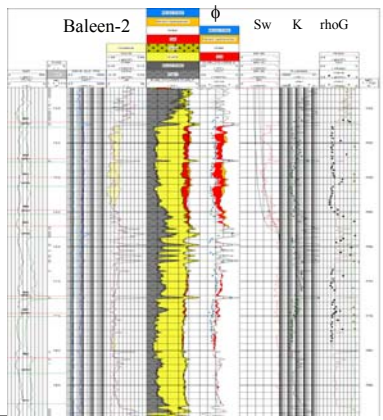
Petrophysical Analysis of Baleen-2 (Complex Model)

- Good wireline data set
- Core measured properties as QC
- SCAL available
- Petrology, XRD from core samples
- Distribution of siderite from FMI and core
- Good match core to log data
- Good match with SW vs capillary pressure derived saturation height function

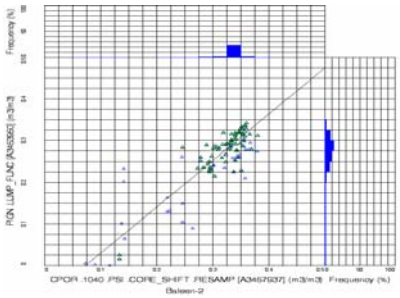
Elanplus Analysis
Complex Model



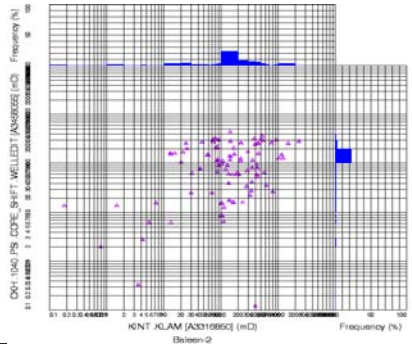
Elanplus Analysis
Lumped Model



Baleen-2 Core Porosity vs PHIE (Complex Model)



Baleen-2 Core Permeability vs K_Lambda (Complex Model)

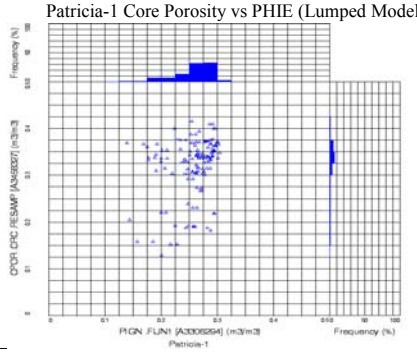


Baleen-2

Petrophysics Analysis Results Gurnard Reservoir	Elanplus Oct 99	Elanplus July 2000 (Complex Model)
Net Reservoir Porosity	28.8%	29.7%
Net Pay Water Saturation	56%	59%
Core Porosity	32.1%	32.1%
Core K	123.2 mD	123.2 mD
K intrinsic / lambda (ar. av.)	102 mD	93 mD
Net to Gross Ratio	~80%	86%
Gross Interval	43m	46.7m
Gross Gas Column	23m	23m

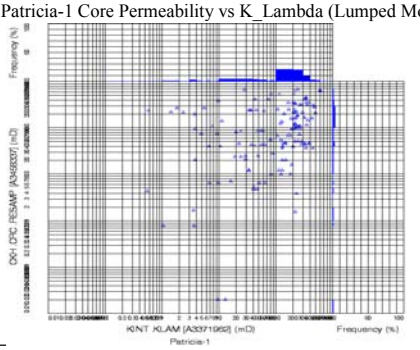
CORE vs LOG POROSITY
PATRICIA 1

Patricia-1 Core Porosity vs PHIE (Lumped Model)



CORE vs LOG PERMEABILITY
PATRICIA 1

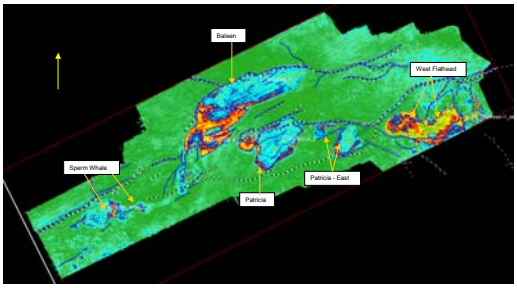
Patricia-1 Core Permeability vs K_Lambda (Lumped Model)



PETROPHYSICS SUMMARY

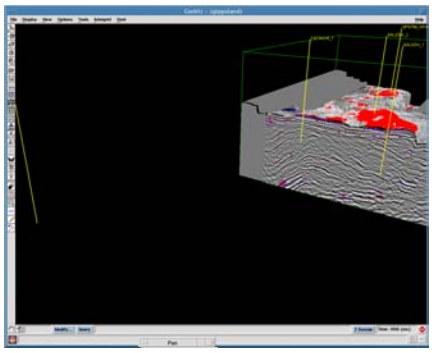
	Patricia-1 Lumped	Baleen-1 Lumped	Baleen-2 Lumped	Baleen-2 Complex
Net Pay Porosity	26%	28%	27%	30%
Net Pay Water Saturations	53%	59%	70%	59%
Core Porosity (av.)	31.3%	na	32.1%	32.1%
Core K (geom av)	36	na	53	53
K from DST	21mD	56mD	-	-
Net to Gross	93%	93%	86%	86%
Gross Reservoir Thickness	31m	35m	40m	40m

3-D Seismic

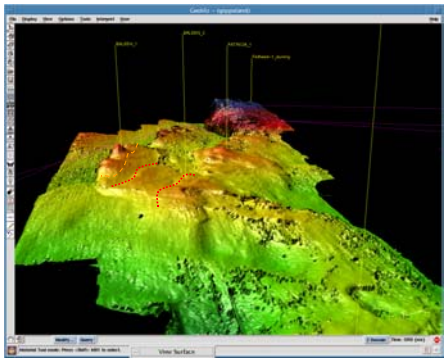


Apparent Polarity on Top Gurnard (top reservoir)

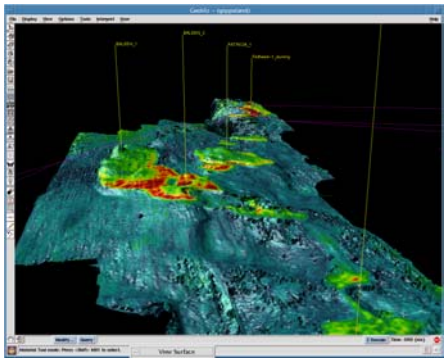
3D Interpretation



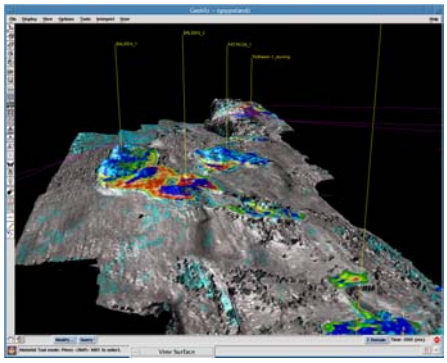
3D Interpretation



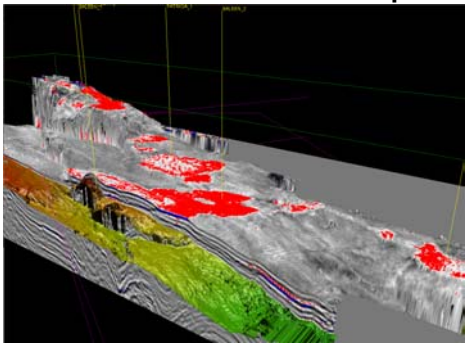
3D Interpretation



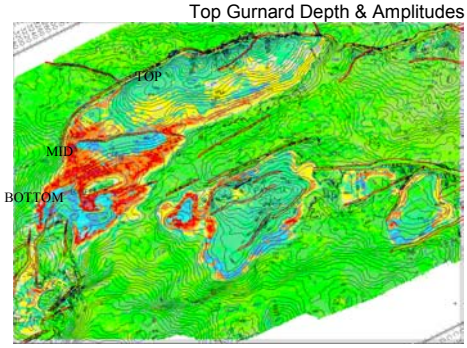
3D Interpretation



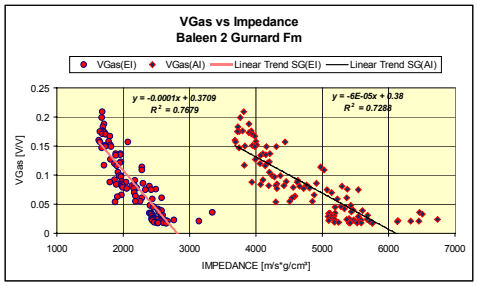
3D Interpretation



Top Gurnard Depth & Amplitudes



Impedance & Reservoir Model



3-D Seismic -- Summary

- Excellent 3D seismic with a vertical resolution of close to 4m (3D Inversion) narrows range of possible GRV's
- Patricia is likely to have a shallower contact (5 – 8m) than Baleen
- Future work will focus on the establishment of a more refined reservoir model through the integration of 3D Inversion and sedimentology

Patricia / Baleen

Reservoir Properties

- 23km Offshore From Orbost
- Shallow Reservoir 710m SS – WD 55m
- Initial Reservoir Pressure 1100 psig
- Reservoir Temperature 122° F
- Porosities 28% - 30%
- Well Core Permeability 0.02 & 300 mD
- Welltest Permeability 21 & 56 mD
- Gross Reservoir Thickness ~40m

Patricia / Baleen

Reserves

- Estimated 59 PJ Sales Gas based on 3 Horizontal Wells Draining Total Volume (Cut-off Rate 5 MMscf/d) – Excluding PE, Sperm Whale, Flathead
- 150 psia Suction Pressure from Day 1 (for forecast)
- 28.4 km 11.89" ID Pipeline Sub-sea Manifold to Plant Inlet
- 2.5 km 7.5" ID Flowlines to Manifold
- 3 ½" - 5 ½" Tubing
- 450m Horizontal Wells

Patricia / Baleen

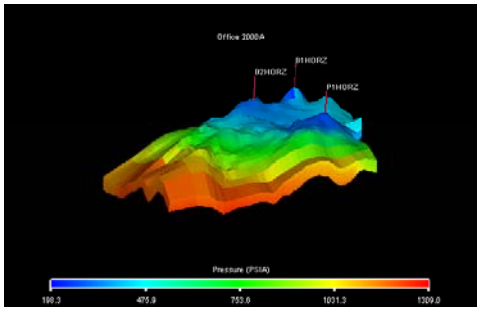
Reservoir Modelling

Architecture

- TOS Using Seismic Map
- Fault Traces from Seismic
- 16 Layers Used Based on Well Log Data
- Log Derived Gross Thickness Corrected Using Seismic Depth Map
- Dz's added to TOS
- Simulation Grid 42x32x16
- GWC 738 m SS for Baleen & 700 m SS in Patricia

Patricia / Baleen

Reservoir Modelling



Patricia / Baleen

Reservoir Modelling

Layer Properties

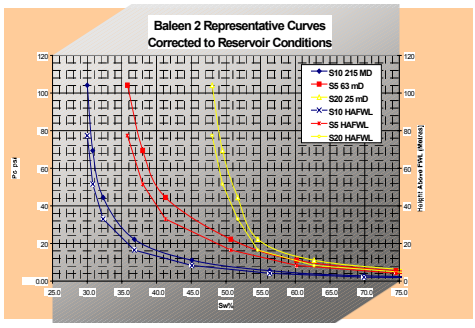
- Properties from ELAN Contoured Using Well Data
- ELAN Properties – Ø, NTG (k from Cores)
- PERMX Multiplied by 0.32 to Match Patricia 1 & Baleen 1 Welltest derived kh
- Sw from Baleen 2 SCAL Capillary Curves – Three Rock Types
- GWC 738 m SS for Baleen & Patricia

Patricia / Baleen

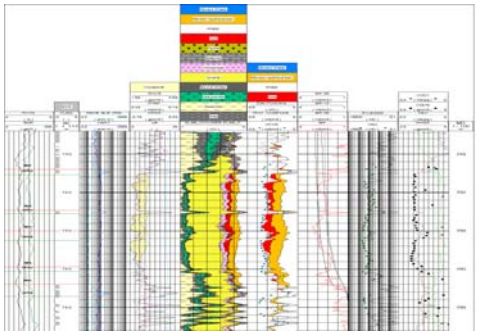
Welltest Results

Well	Test	Zone (mRT)	MMscf/d	FFBHP (psia)	Kh (mD-ft)	K (mD)	S	Comments
Baleen 1 Latrobe	DST 1	700-706	1.6	177	-	-	-	Difficult to interpret; kh possibly 30 mD-ft; S >15
Baleen 1 Gurnard	DST 2A Final Buildup	662-670	6.3	670	2,100	60	3.6	K based on first six units with h = 35 feet; k of 18 mD if h of 116 feet used
Patricia 1 Latrobe	DST 1	744-747	2.0	251	-	-	-	Malfunction DHT; insufficient buildup data Results appear flawed high s >100, high k 186 mD
Patricia 1 Gurnard	DST 2	719-728	6.1	833	2,300	21		Poor CB, partial penetration; k reflects total Gurnard
Patricia 1 Gurnard	DST 3A Final Buildup	703-738	24.1	774	2,625	22	0.9	OMV interpretation

Patricia / Baleen

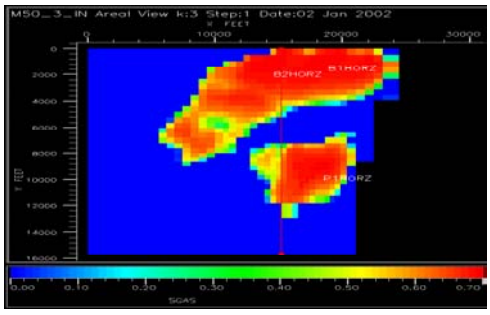


Patricia / Baleen



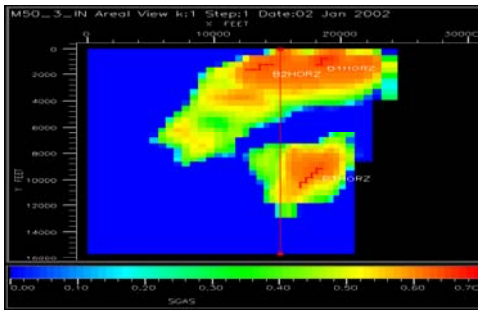
Patricia / Baleen

Sw Layer 3 (Rock Type 1)



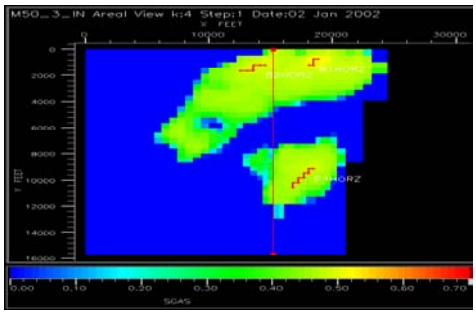
Patricia / Baleen

Sw Layer 1 (Rock Type 2)



Patricia / Baleen

Sw Siderite Layers (Rock Type 3)



Patricia / Baleen

Reservoir Modelling

Model Initialisation

- Relative Permeability End-points Dump Flood Sgr 16%
- Swc Consistent with Swir
- Corey Exponent -- 2 for Gas, 4 for Water
- PVT From PVT$_i$ Software (C_1 97.72%, CO_2 1.32%, N_2 0.66 Mole%)
- Two Equilibrium Regions
- Numerical Aquifer

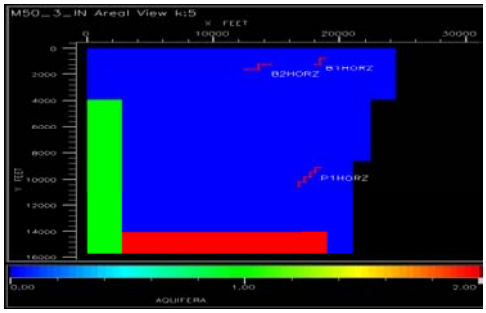
Patricia / Baleen

Reservoir Modelling

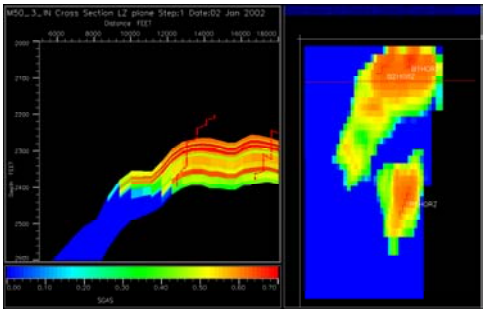
Numerical Aquifer

- One-dimensional row of Cells
- Grid Blocks, Porosity, Permeability, Pressure
- Base Case -- Assumed ReD = 5.0

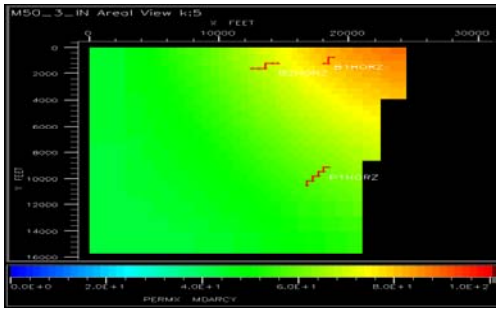
Patricia / Baleen



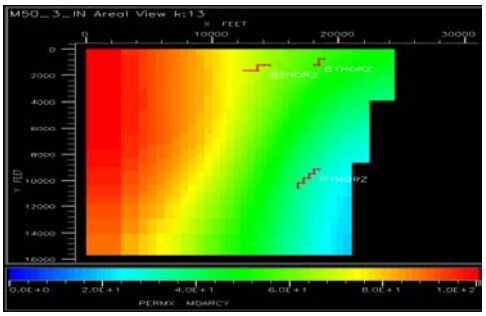
Patricia / Baleen



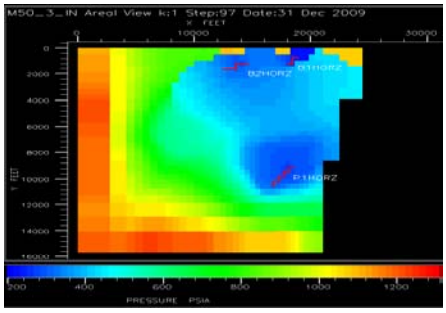
Patricia / Baleen



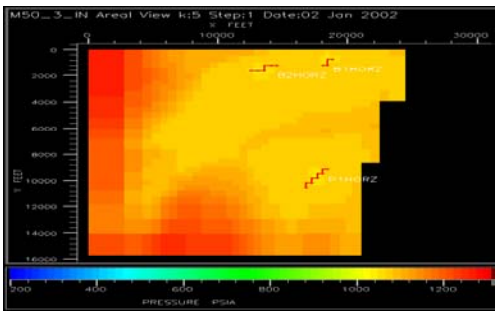
Patricia / Baleen



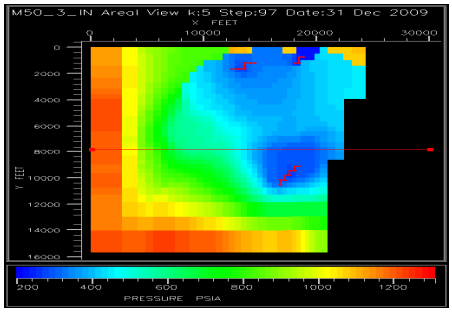
Patricia / Baleen



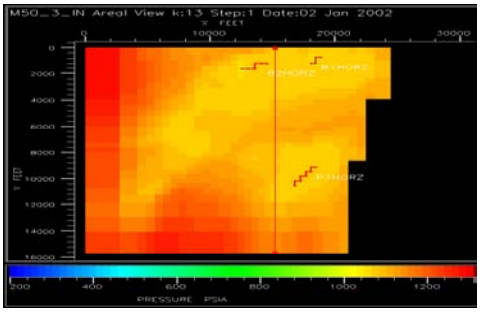
Patricia / Baleen



Patricia / Baleen



Patricia / Baleen



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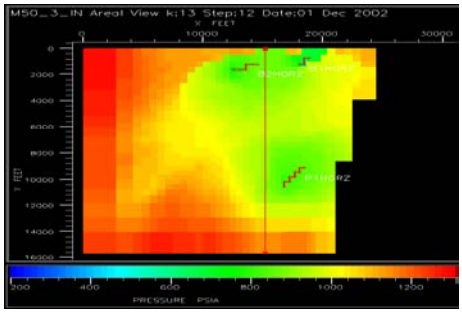
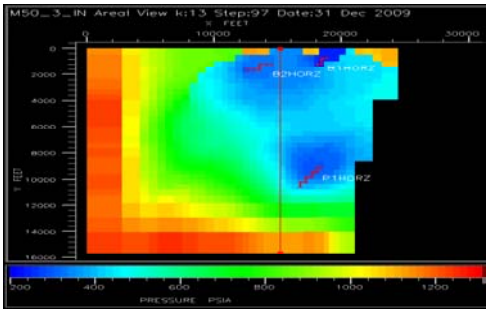


Patricia / Baleen



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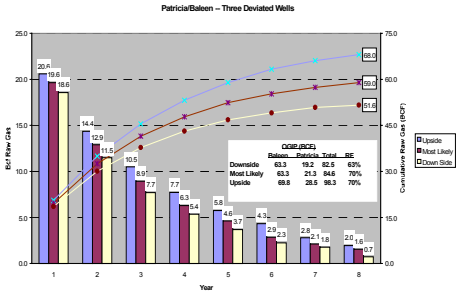


Reservoir Properties Uncertainty

- Patricia GWC (Not Intersected; Seismic Anomaly)
- Degree of Compartmentalization
- GRV (Narrow Variance)
- Ø (Not wide variance)
- Sw (Would be better represented if rock types not constrained by layer) Nonetheless Assigned Sw's Correlate with ELAN Complex Model for Baleen 2

OMV Australia

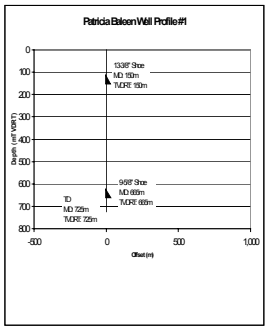
Patricia Baleen Drilling and Completions Summary

August 2000

OMV Australia — Patricia Baleen Preliminary Well Design

Generic Well #1

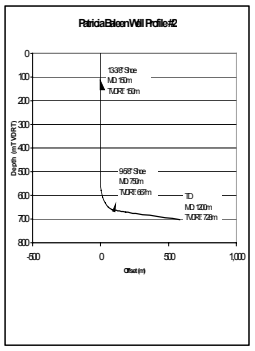
- Satellite Vertical Subsea Well
- Lowest cost and simplest option
- 13 days to drill and complete



OMV Australia — Patricia Baleen Preliminary Well Design

Generic Well #2

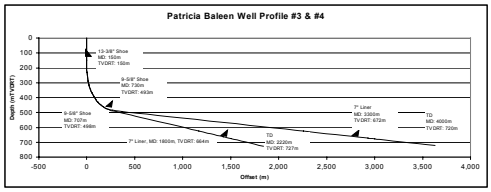
- Satellite Horizontal/High Angle Subsea Well
- 15 days to drill and complete



OMV Australia — Patricia Baleen Preliminary Well Designs

Generic Well #3 & #4

- Extended Reach Well: Platform or Subsea Template
- Both feasible well trajectories
- Well #3: 19 days to drill and complete
- Well #4: 27 days to drill and complete



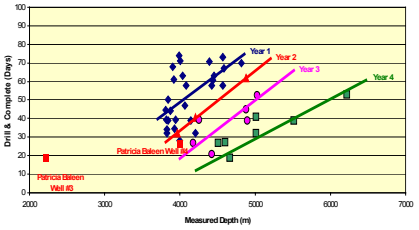
OMV Australia — Patricia Baleen Preliminary Well Designs

- All well designs technically feasible
- Well choice based on overall project economics i.e. platform vs subsea template vs subsea satellite
- Zero intervention policy for all well scenarios
- Rig mobilisation costs identified as significant
- Additional sand control work required

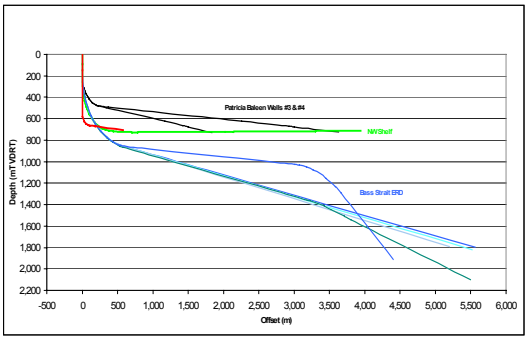
OMV Australia — Patricia Baleen Well Cost Estimates

Well	Estimated Cost (A$ million)	Current Estimated Cost (A$ million)
Well #1	5.0	
Well #2	6.4	5.9
Well #3	8.2	

OMV Australia — Patricia Baleen ER Well Comparison



OMV Australia — Patricia Baleen ER Well Comparison



Patricia Baleen Sand Control

- Operational experience indicated sand production
  - Sand production during Patricia 1 DST
  - Very weak core obtained
- Schlumberger Study
  - Strength testing of core
  - Strength log developed from wireline logs and core data
  - Modelling indicated sand production with a vertical well, cemented and perforated
- Helix Study
  - Focussed on a horizontal/high angle reservoir section
  - Confirmed the need for sand control for any well configuration
  - Proposed expandable sand screens (ESS) over gravel packing

Patricia Baleen Rig Options

- Jackup vs Semi submersible
- Jackup requires dry tow and is more susceptible to weather during mob/demob
- Mob/demob estimate at A$ 10-11 mil. for both jackup and semi-submersible rigs
- OMV sole user of jackup in Bass Strait 2001
- Multiple users for semi-submersible rig in Bass Strait and New Zealand
- Construction interface risks generally lower with semi-submersible

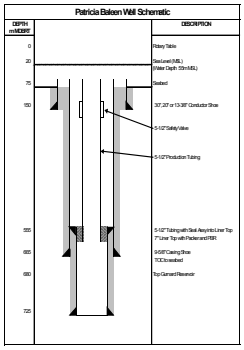
Patricia Baleen Drilling Issues

- Project economics favouring satellite subsea development
- Availability of subsea trees and control systems

Patricia Baleen Revised Subsea Specification

- Trees specified hydraulic only
- Electro-hydraulic system confined to a central manifold
- Operational benefits
  - Less rig time to rig
  - Reduced complexity of equipment
  - Lower operation risk
- Reduced delivery times
- Reduced interface testing requirements
- Currently being evaluated in conjunction with full field implications

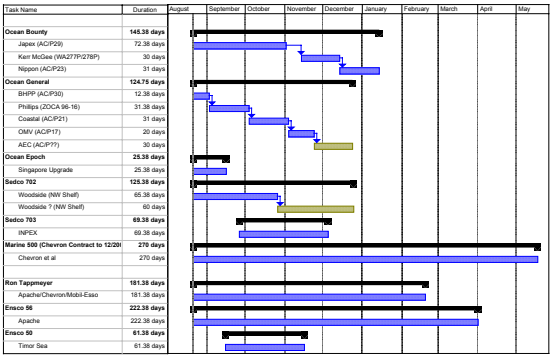
Patricia Baleen Well Schematic



Patricia Baleen Work Program

- Finalise wellhead/tree/manifold/control system evaluation and place order
- Bid and contract drilling rig (shared mob/demob)
- Drilling and completions materials and services procurement
- Sand control
  - Detailed engineering
  - Planning and implementation
- Drilling and completions engineering
  - Detailed design and optimisation
  - Drilling and Completions Program

Rig Schedules



Patricia Baleen – Reservoir Management Philosophy

A Data Acquisition to be cost effective

Patricia Baleen has an expected ultimate recovery of less than 70 Bscf. Approximately 50% of the reserves are expected to be produced in the first two years and the total production life is expected to be about 7 years.

The development will be subsea and so direct measurement of well data will be costly.

Reservoir Management in the Patricia Baleen Development has to provide an understanding of the reservoir model and production behaviour whilst avoiding any excessive cost not commensurate with the modest reserves, short production life and subsea development of the field.

The Reservoir Management plan is based on the development of a first class 'static database' prior to the field development. This database is now considered complete and is populated with wireline log and core data from three discovery wells, plus extensive 3D and 2D seismic data.

The dynamic database, currently populated with the results of flow tests in two vertical discovery wells, will be supplemented with flow tests on the initial completion of the horizontal development wells. These data will allow an effective simulation model to be built to model the reservoir, wells and pipeline. Subsequent data will be restricted to measurements onshore and at the subsea manifold.

B Static Data

An excellent database has been established to support the subsurface evaluation of the Patricia Baleen reservoir.

B.1 Reservoir Model

The Gippsland Basin is a well understood major oil and gas province. The Gurnard formation, sporadically developed over the top Latrobe, is a reservoir of variable quality, grading to a seal. In the Patricia-Baleen gas field most of the Gurnard consists of very fine sandstones that exhibit good reservoir characteristics. Lower permeability siderite / limonite bands are present throughout the reservoir and a number of them can be correlated between the wells drilled to date.

The Gurnard reservoir is sealed above by the claystones of the Lakes Entrance Formation and below by a dense, cemented zone overlying the Latrobe Group coarse clastics.

A 3D seismic survey was obtained in 2000, to aid in defining reservoir structure, gross reservoir thickness, delineation of the siderite / limonite bands, gas-water contact and also to identify any faulting or potential compartmentalisation within the fields.

After processing, a 3D migrated data set with a 6.25m inline and 12.5m crossline spacing was available for interpretation. The 3D dataset was excellent and allowed a clear interpretation of structure and gross reservoir thickness, although some uncertainty remains in picking the gas water interface at the edge. No definite evidence was seen of compartmentalisation. The seismic also assisted in the correlation of the lower permeability beds across the reservoir.

The resultant uncertainties in the Reservoir Model, the Rock Volume and hence GIIP are now considered rather small.

Mud log and MWD correlation logs will be obtained in the development wells and used to refine the Reservoir Model where necessary. In particular, formation tops, bed thickness and the correlation of lower permeability and impermeable beds are likely to be modified.

Additional seismic data are unlikely to improve the current reservoir model as the development wells will be close to already drilled exploration wells. It is not therefore intended to obtain VSP data in the development wells.

B.2 Log and Core Data

Log coverage in the three wells drilled to date, Patricia 1 and Baleen 1 and 2 is good. A full suite of resistivity and porosity logs was obtained in all three wells.

Core was obtained in the Patricia –1 (39.8m) and Baleen – 2 (31.6m) wells. The available core covers most of the Gurnard Formation. Routine core analysis (197 plugs) and Special Core Analysis (21 plugs) along with petrographic studies from Patricia –1 and Baleen –2 have been incorporated into the database.

Complex mineralogy of the Gurnard Formation limits the ability of wireline log interpretation to quantify reservoir parameters. Partially as a consequence of this, seven independent petrophysical studies were carried out between 1982 and 1999. The current analysis (the eighth) presented in the Field Development Plan, benefits from the previous studies plus the available core and log data from Baleen – 2, drilled in 1999. Schlumberger's complex mineralogy model (Elan) has been used together with the core data and petrographic studies to resolve uncertainties in the determination of reservoir parameters. Capillary pressure data has been shown to be more reliable than log data for estimates of water saturation. Log data has, however, been shown to be more reliable than core data to determine porosity.

It is now considered unlikely that additional log and core data in the development wells could significantly improve the accuracy of the present estimates of the values and distribution of permeability, porosity, and water saturation within the reservoir. In particular, it will not be possible to improve the estimates of areal and vertical changes in the reservoir parameters, since the development wells will be close to Patricia –1 and Baleen –1.

There is therefore no requirement for logs or core in the development wells to determine reservoir properties. As noted above (B.1), there is a requirement to obtain logs to allow correlation of reservoir zones and this will be fulfilled by running GR and Resistivity logs in MWD mode. In addition, an Acoustic Scanning Tool will be run across the reservoir to determine hole rugosity prior to running expandable screens.

B.3 Formation Pressures, Free Water Level

Formation pressure profiles were obtained in all three exploration wells and used to determine the free water level, provide insights into formation depletion due to Bass Straits production and identify pressure discontinuities. Baleen –2 reservoir pressure was measured as 1067psi at datum, 680m ss, in 1999. This showed a drop of 38psi compared to Baleen – 1 pressure measured in 1981. It is planned to confirm the current pressure in both structures during the course of a short-term test in the planned development wells.

Different free water levels have been identified in each structure by extrapolation of the Gurnard reservoir gradient to intercept the Latrobe water pressure gradient. Free water levels are estimated to be 738.2mss in Baleen and 730.0 mss in Patricia. Development wells will be drilled and completed above the free water level to prevent early water production. There will therefore be no additional data available on the free water level.

B.4 Fluids

The reservoir gas is dry. It consists largely of methane (97.7%) with 1.3% CO2, and only traces (0.16%) of components higher than ethane. There will be no hydrocarbon liquids production.

Water samples have been obtained from the Latrobe. In Baleen –2, water gradients in the Gurnard and the Latrobe are the same within the limits of the pressure measurements and a common salinity has been assumed for both formations.

As it is planned to flow test the wells on initial completion, additional gas samples can be obtained at modest cost and used to confirm the gas analysis. Once on stream, gas and water samples will be collected regularly at the onshore plant and be monitored for any changes in composition.

C Dynamic Data

C.1 Production Mechanism

Depletion drive is expected to be the predominant production mechanism. For strong aquifer support, the reservoir quality should be in the darcy range; the Gurnard reservoir formation with average permeabilities around 50mD cannot provide significant water influx. Some edge water influx is likely but will be limited by the northern bounding faults to both structures. Vertical water influx is unlikely to be significant because of the basal cemented zone to the Gurnard which provides a partial pressure seal against the underlying Latrobe Group. In addition, the numerous siderite / limonite bands throughout the reservoir will retard the vertical movement of water.

Some water production can be expected. Patricia P1 and Baleen B2 will be drilled as sub horizontal wells and will be completed across the gas water transition zone. Baleen B1 will also be drilled as a sub horizontal well but will not be completed in the transition zone. Simulation runs carried out in support of the development plan indicate that produced water rates in Patricia P1 will be about 80 bwpd and in Baleen B2, about 120 bwpd. Baleen B1 is not expected to produce water. These rates are indicative since well placement is currently being optimised.

C.2 Well Tests

As part of the well completion, it is planned to flow each well to clean up the drilling and completion fluid and then carry out a short term production test. Gauges will be run on wireline which will restrict the depth of measurement to angles around 45o. Effectively the deepest measuring point will be at the bottom of the 5½" tubing around 645m. The objectives of this test will be to confirm well kh, skin, fluid composition, vertical lift performance and reservoir pressure against prediction. It will also be possible to confirm the efficiency of the expandable screens in preventing sand production. A Production Log may be run on coiled tubing if the well parameters differ significantly from the forecast.

Future flow rates will be monitored continuously by means of choke measurements as discussed in Section C.3. Consideration will only be given to obtaining additional downhole data such as pressure data or PLT data, if the well deliverability deviates significantly from prediction and if the remaining reserves justify the cost of a well re-entry.

C.3 Well Production

The development will consist of 2 or 3 subsea wells tied back to a subsea manifold and a pipeline to shore.

Production rates will be controlled by means of an adjustable choke at the subsea manifold. Well flowing pressures and temperatures will be continuously monitored upstream of the choke and at the inlet to the pipeline to shore. As the production mechanism will be depletion drive with only minor water production, the pressure drop across the choke will allow the well flow rate to be estimated to within a few percent by means of a choke equation. It is planned to calibrate the choke equation by flowing wells individually to shore during start up. Thereafter, if well conditions change significantly and the allocation factor (next paragraph) shows significant variation, it may be desirable to re-test individual wells to recalibrate the choke equation.

Total production will be measured on shore using fiscal meters. Each month (day ?), the total fiscal production measured onshore will be compared to the total well production estimated by means of the choke equations, to obtain an allocation factor. The allocated monthly (daily) production per well (and hence each per structure) will be the product of the allocation factor and the monthly (daily) well production estimated using the choke equation.

C.4 Well Pressures

Consideration has been given to the accuracy required in monitoring the variation in well pressures with time and to the possibility of running downhole gauges to monitor bottom hole flowing pressures. The factors considered are summarised in Table 1.

The argument in favour of the use of downhole gauges is the greater accuracy obtained since the gauge is closer to the reservoir and so does not have the extrapolation inaccuracy of a surface manifold gauge. Against this is set the substantial additional cost ($3 million) and the chance that a gauge will fail in the life of the project.

In this case, the greater accuracy of the downhole gauge is not considered crucial. It is more important to have continuous data with a reasonable accuracy. This will allow continuous monitoring of the well flow rate and pressure decline. It has therefore been concluded that the subsea manifold measurements are adequate in this case.

Table 1 – Comparison Downhole and surface gauge

	Downhole gauge	**Subsea Manifold**
Incremental Cost	A$ 3.0 million [1]	0
Expected lifetime	12% chance of failure in first year. 30% chance of failure in 5 years. Unlikely to be cost effective to replace. [2]	Effectively continuous, since easy to replace.
Distance from datum (680 mss)	100m [3]	750m to 3 km
Possible inaccuracy in estimating Bottom Hole Flowing Pressure	< 1psi	< 20psi [4]

Notes

1. *Eliminating the downhole gauges allows simplification in the subsea trees and a significant saving in cost. The A$ 3.0 million quoted comes from a comparison of quotes provided by Clough/ABB. Their fax dated 31st July 2000, provides a cost of A$12.76 million at an exchange rate of A$/$US = 0.59. After eliminating the gauges and simplifying the trees, Clough/ABB quoted (Meeting OMV, Clough/ABB, 18th September) UD$6 million or A$10.17 million at an exchange rate of 0.59. The difference of A$2.6 million has been increased to A$3 million to cover the additional rig time utilised in running gauges.*

2. *The estimates of downhole failure rates have been taken from a Shell paper presented at the OTC in May 1999. (OTC 10945).*

3. *Well design considerations limit the depth at which a gauge can be placed. The requirement to set the 9 5/8" casing at approximately 665m TVDBRT, determines that the liner hanger for the ESS screens must be set at around 635m TVDBRT, above the 9 5/8" shoe track. The gauge must be set above this and above the stab in locator on the tubing, which puts the deepest possible point for a permanent gauge at around 625m. Top reservoir will be at some 680m and so the gauge will be approximately 55m vertically (100m ah) above the top reservoir.*

4. *the produced fluid will be dry gas with very little liquid. An accuracy of some 5-10 % can therefore be expected in predicting the pressure drop back from the subsea manifold to the bottom of the tubing. As the pressure drop will normally be of the order of 200psi or less, the estimate of downhole flowing pressure should normally be within 20 psi of actual. In fact, it should be possible to improve on this accuracy by utilizing the data from the initial well test to tune the model lift performance to actual.*

C.5 Reservoir Performance

A simulation model will be utilised to track reservoir performance.

The reservoir model will be that described in the Field Development Plan. Flow performance curves will be incorporated to allow the whole system to be modelled back to the subsea manifold.

It is likely that some minor modifications to the reservoir model, in particular layer thicknesses, will be incorporated as a result of information obtained in the development wells (B.2). In addition, the initial well tests (C.2) will allow the initial reservoir pressure and well productivity data (kh, skin, vertical lift performance) to be measured.

Reservoir performance will be monitored by matching the simulation model against production data on a regular basis. Well production will be monitored continuously (C.3). Well pressures will be monitored at the subsea manifold (C.4).

Use of the simulation model will allow reservoir and performance changes to be identified as they occur. In addition, the model will be used as a predictive tool to estimate ultimate recovery and provide estimates of the benefit of well intervention, or of additional development.

Appendix B Patricia Baleen Petrophysics Data Averaging For GIIP and Reserves Estimates

1.0 INTRODUCTION

This Appendix covers the methodology used to determine the geological unit (layer) average petrophysical parameters (net-to-gross, porosity, permeability) per well and its uncertainty range for the Patricia-Baleen gas in place and reserves estimates.

The well layer average parameters were contoured between the wells (Patricia-1, Baleen-1 and Baleen-2) and used as input to a 3-D representation of the Geological model (carried out in Eclipse) and subsequent volumetric calculations.

2.0 RESULTS

The layer average petrophysical parameters (net-to-gross, porosity and permeability) per well used for the base case volumetrics are listed in Tables A to C for the GFU units and in Tables D to F for the siderite bands.

3.0 DATA AVERAGING

3.1 CORRELATION

A stratigraphic correlation of the Patricia-Baleen wells yielded eighteen correlatable units (refer section 3.2.6 of main report). Nine of the correlatable units are Gurnard Flow Units (GFUs). Eight siderite/limonite correlatable bands are sandwiched between the Gurnard units and a basal lag unit is the interface between the Gurnard Formation and Latrobe Group.

3.2 CORE DATA

The Baleen-2 and Patricia-1 cores extensively cover the Gurnard Formation. Of the total Gurnard Formation penetrated (143.5m) 48.2% (69.2m) is recovered as core. Considerable analysis was carried out on the cores (description, routine and special core analysis, petrography etc.,). The routine core analysis measurements (Attachment A) were used in the determination of net-to-gross, porosity and permeability estimates for each unit.

3.3 CORE STRESS CORRECTIONS

In the absence of stress measured data for the Patricia-1 well, ambient to in-situ conversion transforms were derived for both porosity and permeability. The transforms were derived from Baleen-2 core data and applied to the Patricia-1 well.

For the permeability an ambient to in-situ stress correction of 0.765 was determined (Figure 1). A Klinkenberg correction factor of 0.815 for in-situ permeabilities < 100mD and 0.90 for in-situ permeabilities >= 100mD (Figures 2 and 3) was derived.

For the porosity the ambient to in-situ stress correction factor is 0.96 (Figure 4).

The results of the application of the above transforms to the Patricia-1 ambient core measured data are given in Attachment A.

Figure 1

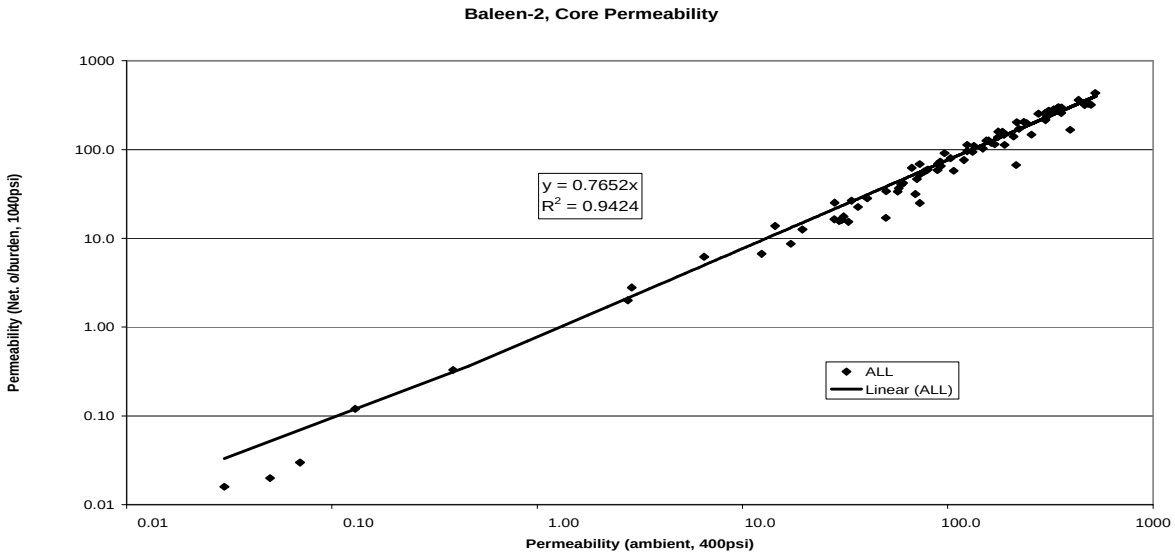


Figure 2

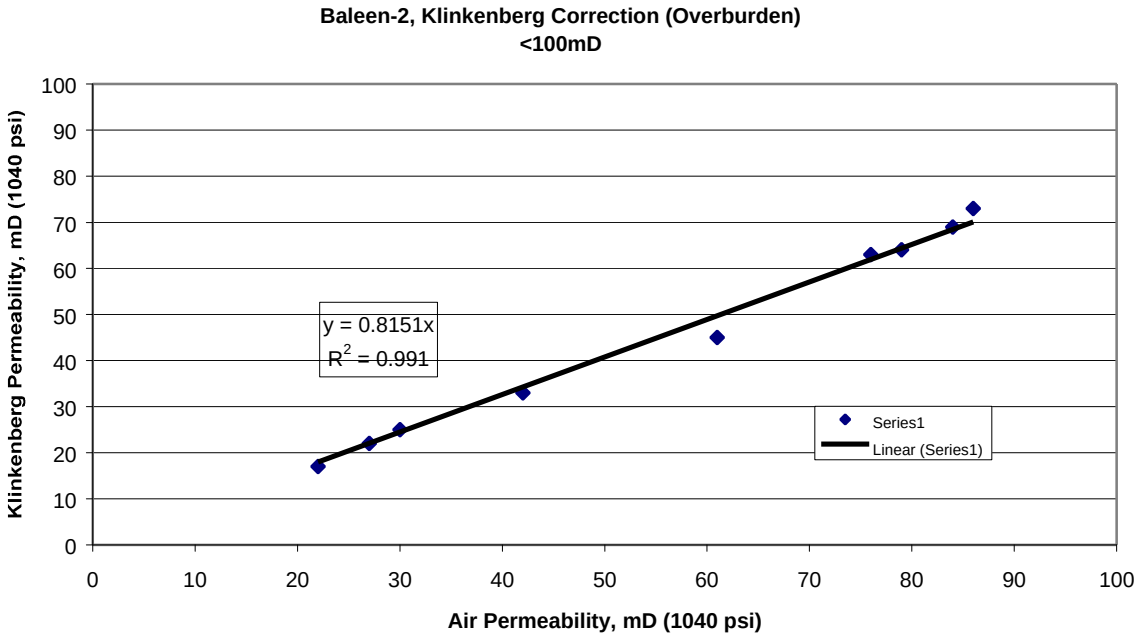


Figure 3

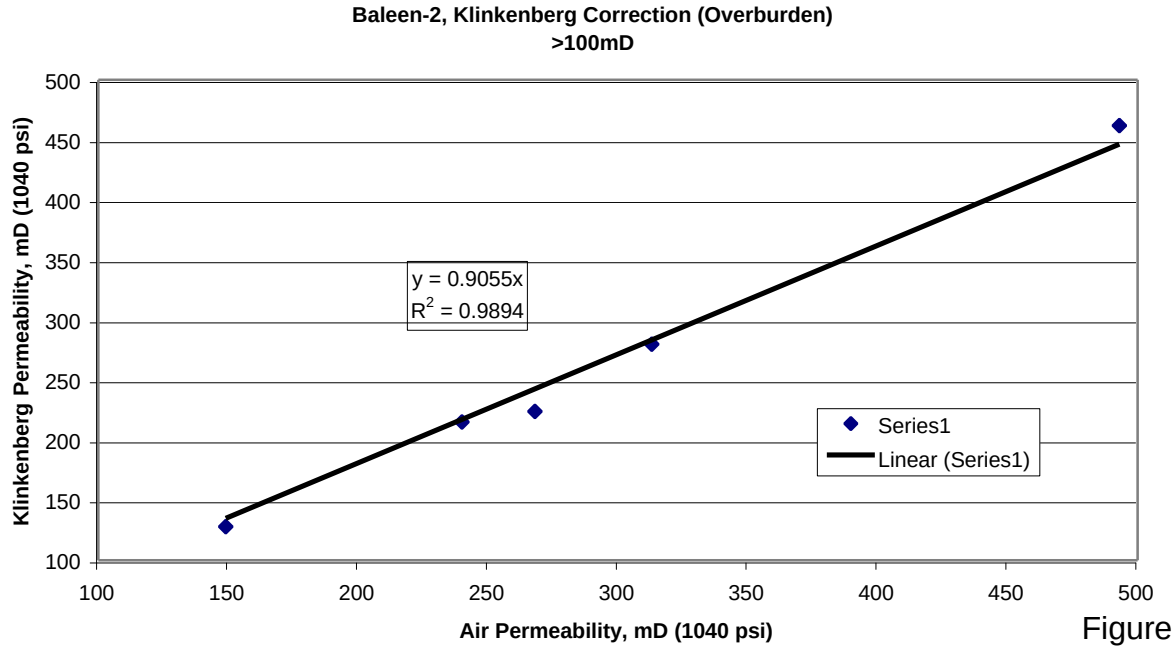
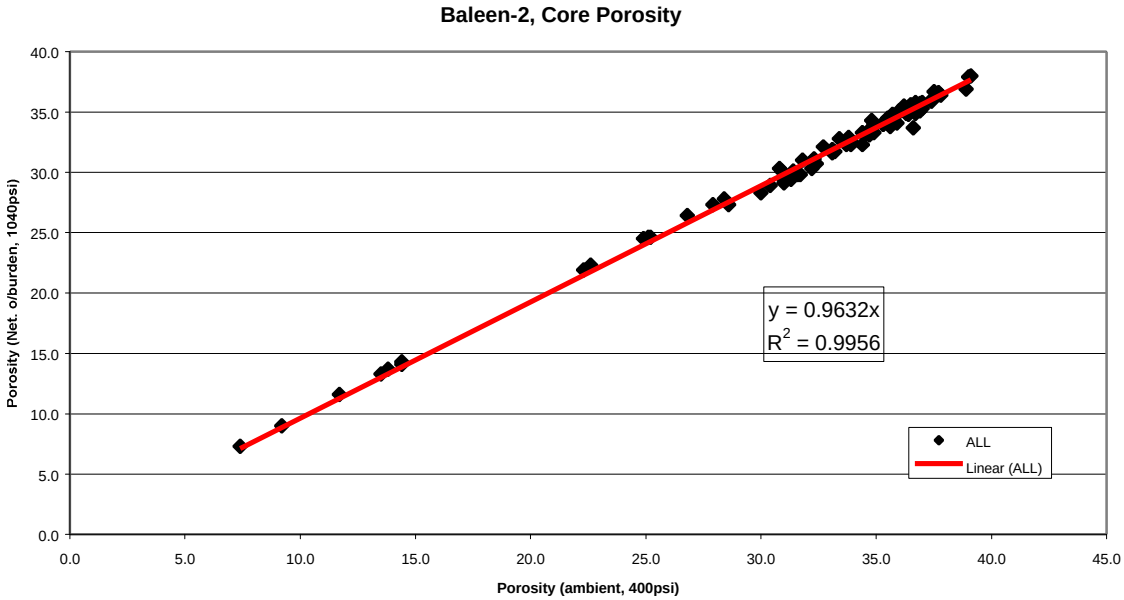


Figure 3

Figure 4



3.3 WIRELINE LOG EVALUATION

Schlumberger Elan wireline log analysis was carried out on Baleen-1, Baleen-2 and Patricia-1 wells. The objective of the Elan analysis and its calibration with core data (Baleen-2 and Patricia-1 wells) was to establish an Elan model for porosity and permeability prediction in future wells along with the non-cored Baleen-1 well.

In Baleen-2 a 'complex' Elan model encompassing the well's extensive suite of logs was created. A second 'simple' Elan model (''simple'') was created based on a sub set suite of logs to allow for model transfer to Baleen-1 and Patricia-1 wells. A summary of the layer average porosity and permeability (K-lambda) values for the Elan models per well are given in Tables G, H, I and J.

A rigorous attempt at predicting saturation from the wireline logs was not attempted as the conductive nature of some of the minerals (e.g. siderite) in the formation complicated the saturation prediction. The capillary pressure curves were used for the saturation prediction in the volumetric model and are covered in the PDP.

3.4 CORE LAYER AVERAGING

For the most part the routine plugging of the core was carried out every foot, in a non-biased[1] way. A statistical meaningful comparison of the measured plug data with the wireline log data (sampled every 6 inches) averaged[2] per layer was carried out.

The averaging of log calculated porosity and permeability data for the GFU units excluded any sideritic zones within the units to obtain representative average data for the Gurnard Flow Units (GFU). Sideritic zones within the GFU units that were not considered to be laterally extensive or correlatable between the wells were excluded from the GFU log averaging. A corresponding discrimination was carried out on the core data using the core grain density as a discriminator.

A summary of the layer average porosity and permeability values from the core measured (and core calculated) porosity per well are given in Tables G, H, I and J.

4.0 METHODOLOGY

The methodology used to obtain the layer average parameters (net-to-gross, porosity and permeability) as input to the in-place volumetric and reserves estimates are discussed below.

4.1 NET-TO-GROSS

The net-to-gross for the Gurnard units within the Patricia-1, Baleen-1 and Baleen-2 wells was initially estimated as 100% from the wireline logs and available core data. The net-to-gross for the Gurnard units was revised downwards to account for sideritic zones within the GFU units, that were not considered to be laterally extensive or correlatable between the wells. This is a conservative approach for the in-place volumetric estimates but not an unreasonable approach where it is assumed that the sideritic sections provide minimum flow benefit characteristics (see Siderite permeability section, below) for reserves estimates.

The net-to-gross inputs for the most likely and low case scenarios were assumed to be the same. A net-to-gross of 100% was assumed for the high case scenario.

1 There may have been a slight bias in the Baleen-2 data set as non-reservoir was avoided at times in the routine plugging of the core in the Gurnard flow units.

2 Arithmetic averaging was carried out on the porosity data and Geometric averaging was carried out on the permeability data.

The net-to-gross for the Siderite units within the Patricia-1, Baleen-1 and Baleen-2 wells was estimated as 100% from the wireline logs and available core data for the low, most likely and high case scenarios. This is reasonable for in-place volumetric estimates. However it is assumed that the sideritic sections provide minimum flow benefit characteristics (see Siderite permeability section, below) for reserves estimates.

The porosity and permeability are discussed below.

4.2 GURNARD UNITS

POROSITY

Baleen-2

The total porosity estimate (PHIT) from the Elan 'complex' model is a good match with the overburden core measured porosity (Table B). However it is expected that there would be a better match between the effective porosity (PHIE) from the simple model (or complex model) with the overburden core measured porosity as the latter was measured at effective porosity conditions (critical point drying). The confidence on the Elan PHIT estimate is good based on the reconstruction of the input curves and the match of the measured and the Elan model predicted grain densities. This raises some uncertainty on the core measurement conditions.

Given this uncertainty the layer average effective porosity (PHIE) from the 'complex' model was 'conservatively' assumed to represent the layer average total porosity of the well for volumetric estimate. For the volumetric uncertainty estimate the porosity was assumed to be a factor of 10% higher at a P10 level corresponding to the difference between PHIT and PHIE.

The statistical significance of the standard deviation associated with average log and core porosities was not taken into account for the upside (P10) and downside (P90) scenarios.

Patricia-1

Elan's simple model total porosity estimate (PHIT) underestimates the calculated overburden core porosity (Table B) but provides a better match than the lower Elan effective porosity (PHIE). The overburden calculated core porosity is believed to be at total porosity conditions. However some uncertainty on the validity of the 1987 measurement conditions of core total porosity (ambient) exist.

For the volumetric estimate a 'conservative' approach was taken. The layer average effective porosity from Elan's 'simple' model was taken to represent the layer average total porosity of the well. The upside on the porosity could be 20% or higher. For the volumetric uncertainty estimate the porosity was assumed to be a factor of 10% higher at a P10 level.

The statistical significance of the standard deviation associated with average log and core porosities was not taken into account for the upside (P10) and downside (P90) scenarios.

Baleen-1

For the volumetric estimate the Baleen-1 layer average effective porosity (PHIE) from Elan's 'simple' model was taken to represent the layer average total porosity of the well (Table B). This was in the absence of core data and as an extension of the assumptions in Patricia-1 and Baleen-2. The upside on the porosity could be 20% or higher. For the volumetric uncertainty estimate the layer average porosity was assumed to be a factor of 10% higher at a P10 level.

PERMEABILITY

Baleen-2

The estimate of the Baleen-2 layer average permeability from wireline logs honours the contrasts in the core measured layer average permeabilities. The Elan 'simple' model layer average permeability yields a slightly better match both in relative and absolute terms than the Elan 'complex' model layer average permeability. In both cases the overburden core measured average permeability per layer is less than the Elan log averages.

For the reserves estimate the overburden core measured air permeability was assumed as the layer average air permeability (Table D – summary of layer averages). A further reduction of 68% was applied to the permeability consistent with core/production test calibration (section 4.2.2 of PDP).

Patricia-1

The layer average permeability estimate from the 'simple' model shows a relatively good match with the overburden core calculated layer average permeability. The GFU7 layer is an exception to this (Core vs. log, 31mD vs. 248mD respectively). The 'simple' model layer average permeability honours the core layer average permeability contrasts reasonably well. In general the overburden core calculated layer average permeability is lower than the Elan 'simple' model estimate.

For the reserves estimate the overburden core calculated layer average air permeability was assumed to represent the layer average air permeability (Table D – summary of layer averages). A further reduction of 68% was applied to the permeability consistent with core/production test calibration (section 4.2.2 of PDP).

Baleen-1

The layer average permeability estimate from the Elan 'simple' model (Table J) was considered on the high side for a most likely scenario. A crossplot (Figure 5) of the Patricia-1 and Baleen-2 core porosities and the permeabilities averaged for the Gurnard layers was used to constrain the Baleen-1 permeability estimates. Some estimates were further reduced in line with the trend seen in the other wells to arrive at the final Baleen-1 estimates (Table C).

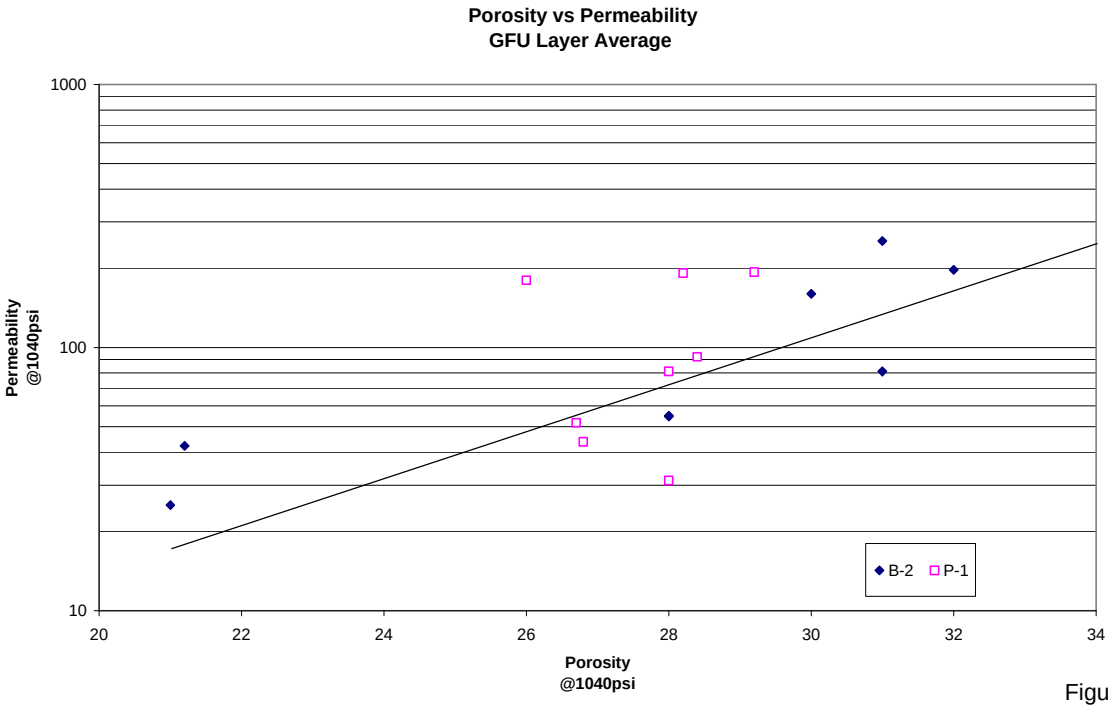


Figure 5

A further reduction of 68% was applied to the permeability consistent with core/production test calibration (section 4.2.2 of PDP) for the reserves modelling.

The contoured most likely permeability was not varied for the recoverable volume uncertainty estimate (section 4.6.1 of PDP).

4.3 SIDERITE UNITS

Porosity

The average porosity of the 'siderite' layers is estimated from the core plug measured data in both Patricia-1 and Baleen-2. The average porosity of the 'siderite' layer for Baleen-1 was estimated from a comparison of the log character (e.g. GR, density and resistivity) in Baleen-1 with the logs and core measured 'siderite' porosities in Patricia-1 and Baleen-2.

An Elan porosity model was not generated for the 'siderite' layers as any estimate of porosity from the logs would have a large degree of uncertainty due to the uncertainty in the matrix mineral composition and its apparent grain density along with the inadequate resolution of some logging tools (e.g. the density) over some of the siderite bands.

4.4 PERMEABILITY

As with the porosity (see above), permeability was not derived from the logs (Elan) over the siderite bands.

The siderite core plug in-situ air permeability measurements range from 0.02mD to 155mD for both Patricia-1 and Baleen-2 wells.

For the reserves estimate the in-situ average air permeability for the 'siderite' layers in each well was assumed to be 1mD for the base case. The low and high case scenarios were assumed as 0.02mD and 10mD respectively (Table D – summary of layer averages). A further reduction of 68% was applied to the permeability consistent with core/production test calibration (section 4.2.2 of PDP).

5.0 OBSERVATIONS

The Patricia-1 core porosities are on average greater than the Baleen-2 core porosities for the same geological units. It is suspected that the Patricia-1 measured porosities are total porosities as the core was dried at high temperatures before measurement were made. However the Baleen-2 measurements were carried out under 'critical point drying' conditions and hence are supposedly 'effective porosity' measurements.

The confining pressure used in the measurement of 'ambient' porosity and 'ambient' permeability on Patricia-1 plugs is unknown.

The hydrostatic pressure selected to simulate in-situ conditions for core plug measurements was determined from Nieto stress correction method. A more direct and formation specific estimate of this hydrostatic pressure can be determined from the pore volume change as a function of applied hydrostatic stress. The applied hydrostatic stress can be converted to uixaxial stress using poissons ratio and pore volume change.

PATRICIA-BALEEN

GURNARD UNITS

TABLE A

AVERAGE LAYER NET TO GROSS

	BALEEN-2 N/G	PATRICIA-1 N/G	BALEEN-1 N/G
GFU1	0	0.00	0.00
GFU2	1.00	1.00	1.00
GFU3	1.00	0.86	1.00
GFU4	1.00	0.92	1.00
GFU5	1.00	1.00	1.00
GFU6	0.85	0.86	1.00
GFU7	1.00	1.00	1.00
GFU8	1.00	0.92	0.88
GFU9	1.00	0.80	0.90

TABLE B

AVERAGE LAYER POROSITY

	BALEEN-2 %	PATRICIA-1 %	BALEEN-1 %
GFU1	0.0	0.0	0.0
GFU2	28.0	28.0	30.0
GFU3	32.0	28.2	32.0
GFU4	30.0	29.2	34.0
GFU5	21.0	26.0	29.0
GFU6	21.2	26.8	28.0
GFU7	31.0	28.0	30.0
GFU8	31.0	28.4	30.4
GFU9	28.0	26.7	27.0

TABLE C

GEOMETRICAL AVERAGE LAYER PERMEABILITY

	BALEEN-2 mD	PATRICIA-1 mD	BALEEN-1 mD
GFU1	na	na	0
GFU2	55	81	100
GFU3	197	192	200
GFU4	160	193	250
GFU5	25	180	140
GFU6	42	44	90
GFU7	81	31	61
GFU8	254	92	175
GFU9	55	52	52

SIDERITE UNITS

TABLE D

AVERAGE LAYER NET TO GROSS

	BALEEN-2 N/G	PATRICIA-1 N/G	BALEEN-1 N/G
SB1	1.00	1.00	1.00
SB2	1.00	1.00	1.00
SB3	1.00	1.00	1.00
SB4	1.00	1.00	1.00
SB5	1.00	1.00	1.00
SB6	1.00	1.00	1.00
SB7	1.00	1.00	1.00
SB8	1.00	1.00	1.00

TABLE E

AVERAGE LAYER POROSITY

	BALEEN-2 %	PATRICIA-1 %	BALEEN-1 %
SB1	7.3	13.0	20.0
SB2	13.3	24.0	30.0
SB3	27.5	18.0	21.0
SB4	14.1	24.0	27.0
SB5	17.7	28.7	19.0
SB6	11.6	19.2	24.0
SB7	27.0	19.1	19.0
SB8	26.0	24.6	20.0

TABLE F

GEOMETRICAL AVERAGE LAYER PERMEABILITY

	BALEEN-2 mD	PATRICIA-1 mD	BALEEN-1 mD
SB1	0.02	0.02	0.02
SB2	0.02	0.02	0.02
SB3	0.02	0.02	0.02
SB4	0.02	0.02	0.02
SB5	0.02	0.02	0.02
SB6	0.02	0.02	0.02
SB7	0.02	0.02	0.02
SB8	0.02	0.02	0.02

SIDERITE BAND LAYER PERMEABILITIES ASSUMED TO BE PRACTICALLY ZERO FOR LOW CASE

TABLE G

POROSITY

		BALEEN-2					PATRICIA-1				BALEEN-1	
		Porosity (%)					Porosity (%)				Porosity (%)	
		Core	Log (Complex)		Log (Lumped)		Core	Log			Log	
		Measured @1040psi	PHIT	PHIE	PHIT	PHIE	Calculated @1040psi	PHIT	PHIE		PHIT	PHIE
GFU1		na	na		na		na	30	23		31	24
GFU2	mean	**31.3**	30	28	30	28	**34.1**	30	28		31	30
	std. Dev.	2.7										
GFU3	mean	**35.0**	35	32	34	32	**34.6**	30	28		33	32
	std. Dev.	0.7										
GFU4	mean	**34.0**	33	30	34	31	**36.9**	31	29		35	34
	std. Dev.	2.0										
GFU5	mean	**24.5**	27	21	28	23	**27.6**	28	26		32	29
	std. Dev.											
GFU6	mean	**28.9**	26	21	27	23	**31.5**	29	26		31	28
	std. Dev.	6.5										
GFU7	mean	**34.1**	33	31	32	28	**34.2**	30	28		32	30
	std. Dev.	1.6										
GFU8	mean	**35.1**	32	31	33	31	**31.0**	30	28		32	30
	std. Dev.	0.8										
GFU9	mean	**na**	31	28	30	27	**31.3**	29	25		29	27
	std. Dev.											
BCZ	mean	**na**					**24.7**					
	std. Dev.											

TABLE H

POROSITY

* Core with Log Siderite discriminator applied

		BALEEN-2					PATRICIA-1				BALEEN-1	
		Porosity (%)					Porosity (%)				Porosity (%)	
		Core	Log (Complex)		Log (Lumped)		Core	Log			Log	
		Measured @1040psi	PHIT	PHIE	PHIT	PHIE	Calculated @1040psi	PHIT	PHIE		PHIT	PHIE
GFU1		na	na		na		na	30	23		31	24
GFU2	mean	**31.3**	30	28	30	28	**34.0**	30	28		31	30
	std. Dev.	**2.7**										
GFU3	mean	**35.0**	35	32	34	32	**34.6**	30	28		33	32
	std. Dev.	**0.7**										
GFU4	mean	**34.0**	33	30	34	31	**36.8**	31	29		35	34
	std. Dev.	**2.0**										
GFU5	mean	**24.5**	27	21	28	23	**36.8**	28	26		32	29
	std. Dev.	**0.0**										
*GFU6	mean	**31.9**	26	21	27	23	**34.5**	29	26		31	28
	std. Dev.	**3.1**										
GFU7	mean	**34.1**	33	31	32	28	**34.2**	30	28		32	30
	std. Dev.	**1.6**										
GFU8	mean	**35.1**	32	31	33	31	**33.4**	30	28		32	30
	std. Dev.	**0.8**										
GFU9	mean	**na**	31	28	30	27	**33.1**	29	25		29	27
	std. Dev.											
BCZ	mean	**na**					**24.7**					
	std. Dev.											

* GFU6 core data discriminated on reducing plug numbers from 21 to 16

Notes
Baleen-2 plugged with bias to reservoir rock
Patricia-1 plugged on regular spacing
Of the total Gurnard Fm penetrated (143.5m) there is 69.2m (48.2%) recovered as core.
Upper part of GFU6 in B-2 more heavily cemented w/ siderite than at P-1
GFUs 3,4,7 & 8 are the best quality, GFU6 improves at P-1 and B-1 (from logs)

TABLE I

PERMEABILITY
Geometric Averaging

		BALEEN-2			PATRICIA-1		BALEEN-1
		Permeability (mD)					
		Core	Log (Complex)	Log (Lumped)	Core	Log (Lumped)	Log (Lumped)
		Measured @1040psi	K	K	Calculated @1040psi	K	K
GFU1		na	na	na	na		na
GFU2	mean	**55**	**401**	**174**	**81**	**230**	**473**
GFU3	mean	**197**	**191**	**338**	**192**	**299**	**917**
GFU4	mean	**160**	**216**	**198**	**193**	**372**	**1467**
GFU5	mean	**25**	**14**	**13**	**30**	**128**	**195**
GFU6	mean	**19**	**36**	**25**	**27**	**81**	**173**
GFU7	mean	**81**	**252**	**111**	**31**	**248**	**295**
GFU8	mean	**254**	**515**	**314**	**61**	**217**	**285**
GFU9	mean	**na**	**133**	**105**	**37**	**34**	**123**
BCZ	mean	**na**			**2**		

Notes
Baleen-2 plugged with bias to reservoir rock
Patricia-1 plugged on regular spacing
Of the total Gurnard Fm penetrated (143.5m) there is 69.2m (48.2%) recovered as core.
Upper part of GFU6 in B-2 more heavily cemented w/ siderite than at P-1
GFUs 3,4,7 & 8 are the best quality, GFU6 improves at P-1 and B-1 (from logs)

TABLE J

PERMEABILITY
Geometric Averaging
* Core with Log Siderite discriminator applied

		BALEEN-2			PATRICIA-1		BALEEN-1
		Permeability (mD)					
		*Core	Log (Complex)	Log (Lumped)	*Core	Log (Lumped)	Log (Lumped)
		Measured @1040psi	K	K	Calculated @1040psi	K	K
GFU1		na	na	na	na		na
GFU2	mean	**55**	**401**	**174**	**81**	**230**	**473**
GFU3	mean	**197**	**191**	**338**	**192**	**299**	**917**
GFU4	mean	**160**	**216**	**198**	**193**	**372**	**1467**
GFU5	mean	**25**	**14**	**13**	**180**	**128**	**195**
*GFU6	mean	**42**	**36**	**25**	**44**	**81**	**173**
GFU7	mean	**81**	**252**	**111**	**31**	**248**	**295**
GFU8	mean	**254**	**515**	**314**	**92**	**217**	**285**
GFU9	mean	**na**	**133**	**105**	**52**	**34**	**123**
BCZ	mean	**na**			**2**		

* GFU6 core data discriminated on reducing plug numbers from 21 to 16

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BALEEN-2 CORE DATA

Company : Basin Oil NL
Well : Baleen-2
Field : Baleen
Core Int. : 746.00m - 762.20m
Core Int. : 763.70m - 779.50m

Date 2/11/99
File 0308-02
Location VIC/RL5
Analysts pnc, ijm, kw

Sample Number	Depth	Dir	Porosity (%) 400 psi	Porosity (%) 700 psi	Porosity (%) 1040psi	Grain Density	Permeability (mD) 400 psi	Permeability (mD) 700 psi	Permeability (mD) 1040psi	
1	746.21	R	28.6	27.9	27.3	3.04	69.5	43.0	31.5	
2	746.56	R	34.4	33.4	32.3	2.80	49.9	26.0	17.0	
3	746.81	R	35.6	34.8	33.8	2.88	209	172	141	
4	747.08	R	7.4	7.3	7.3	3.17	0.03	0.02	0.02	
5	747.53	R	31.8	31.6	31.0	2.66	60.6	55.2	41.9	
	MEAN		**27.6**	**27.0**	**26.3**	**2.91**	**16.7**	**11.6**	**8.7**	SB1
	Std DEV.		**11.6**	**11.3**	**10.9**	**0.20**				
6	747.79	R	33.8	33.4	32.9	2.67	132	113	93.8	
8	748.45	R	36.9	36.0	35.1	2.66	299	247	215	
9	748.82	R	34.9	34.0	33.3	2.65	188	165	146	
10	749.20	R	35.3	35.0	34.0	2.67	158	151	126	
11	749.56	R	25.2	24.9	24.6	2.77	34.0	29.2	26.6	
12	749.80	R	33.9	33.0	32.3	2.66	103	87.3	80.0	
13	750.20	R	32.2	31.7	30.9	2.67	57.6	46.1	36.6	
14	750.50	R	33.2	32.3	31.7	2.65	92.3	75.5	65.2	
15	750.80	R	31.4	30.6	30.1	2.66	40.5	33.3	28.2	
16	751.20	R	32.4	31.5	30.7	2.66	36.5	27.5	22.6	
17	751.50	R	30.4	29.5	28.9	2.84	50.1	40.1	33.9	
18	751.81	R	31.6	30.4	29.8	2.66	28.0	19.0	16.4	
19	752.12	R	33.7	32.8	32.3	2.66	89.0	68.3	58.6	
	MEAN		**32.7**	**31.9**	**31.3**	**2.68**	**78.1**	**63.9**	**54.7**	**GFU2**
	Std DEV.		**2.9**	**2.8**	**2.7**	**0.06**				
20	752.43	R	13.5	13.4	13.3	3.03	2.89	2.83	2.80	SB2
21	752.81	R	35.5	34.8	34.1	2.68	169	136	115	
22	753.19	R	35.7	35.4	34.8	2.66	184	171	158	
23	753.49	R	35.3	34.6	34.1	2.65	154	137	126	
24	753.79	R	36.7	36.1	35.7	2.68	234	217	205	
25	754.20	R	36.0	35.5	35.1	2.67	327	302	282	
26	754.50	R	36.2	35.7	35.5	2.68	346	318	301	
27	754.80	R	36.5	36.0	35.6	2.69	342	313	293	
	MEAN		**36.0**	**35.4**	**35.0**	**2.67**	**238.1**	**214.3**	**197.4**	**GFU3**
	Std DEV.		**0.5**	**0.6**	**0.7**	**0.01**				
28	755.11	R	27.9	27.6	27.3	2.79	66.7	63.8	62.3	
29	755.49	R	28.4	28.1	27.8	2.78	96.4	93.3	90.8	
	MEAN		**28.2**	**27.9**	**27.6**	**2.79**	**80.2**	**77.2**	**75.2**	SB3
	Std DEV.		**0.4**	**0.4**	**0.4**	**0.01**				
30	755.78	R	30.8	30.6	30.3	2.75	217	208	203	
31	756.19	R	37.7	37.2	36.6	2.67	433	393	363	
32	756.49	R	37.4	36.5	36.0	2.65	355	324	295	
33	756.80	R	37.0	36.2	35.8	2.66	301	279	256	
34	757.14	R	37.4	36.5	35.9	2.66	309	273	244	
35	757.49	R	36.3	35.5	34.9	2.65	222	193	171	
36	757.80	R	33.9	33.1	32.6	2.64	124	107	96.4	
37	758.19	R	34.6	33.8	33.3	2.63	175	154	138	
38	758.50	R	33.1	32.4	31.9	2.63	89.6	77.5	68.9	
39	758.80	R	32.3	31.6	31.1	2.63	59.3	46.6	40.2	
40	759.17	R	34.4	33.7	33.3	2.65	134	119	110	
41	759.51	R	36.4	35.5	34.8	2.73	256	176	147	

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42	759.82	R	36.9	36.2	35.7	2.69	187	167	153	
43	760.19	R	36.7	36.3	35.8	2.73	482	382	328	
44	760.46	R	32.7	32.4	32.1	2.80	394	218	167	
	MEAN		**35.2**	**34.5**	**34.0**	**2.68**	**215.0**	**180.0**	**160.1**	**GFU4**
	Std DEV.		**2.2**	**2.1**	**2.0**	**0.05**				
45	760.72	R	14.4	14.2	14.1	3.01	6.5	6.3	6.2	SB4
46	761.19	R	**24.9**	**24.7**	**24.5**	**2.94**	**28.1**	**26.2**	**25.2**	GFU5
47	763.87	R	9.2	9.1	9.0	3.09	0.07	0.05	0.03	
48	764.19	R	26.8	26.6	26.4	2.95	72.8	70.5	68.8	
	MEAN		**18.0**	**17.9**	**17.7**	**3.0**	**2.3**	**1.9**	**1.4**	SB5
	Std DEV.		**12.4**	**12.4**	**12.3**	**0.1**				
49	764.60	R	34.8	34.5	34.3	2.80	276	262	253	
50	764.89	R	37.5	37.0	36.7	2.77	310	289	274	
51	765.14	R	39.0	38.4	37.9	2.71	242	217	198	
52	765.59	R	14.4	14.4	14.3	3.04	0.05	0.03	0.02	
53	765.86	R	30.9	30.5	30.1	2.90	176	165	159	
54	766.22	R	22.6	22.4	22.3	3.07	2.76	2.28	2.00	
55	766.56	R	37.8	37.1	36.4	2.77	148	118	103	
56	766.90	R	34.7	34.1	33.5	2.89	120	90.1	76.2	
57	767.17	R	25.1	24.8	24.6	3.01	57.0	41.4	33.6	
58	767.63	R	13.8	13.7	13.7	3.03	0.39	0.35	0.33	
59	767.98	R	22.3	22.1	21.9	3.00	14.4	14.0	13.8	
60	768.30	R	33.1	32.3	31.6	2.67	91.9	80.4	73.2	
61	768.59	R	32.2	31.1	30.3	2.66	29.6	19.3	15.7	
62	768.89	R	31.0	30.1	29.4	2.65	32.8	19.3	15.4	
63	769.20	R	36.6	35.1	33.7	2.80	215	108	67.0	
64	769.63	R	31.2	30.3	29.6	2.67	19.6	15.2	12.6	
65	769.98	R	31.0	29.9	29.1	2.68	12.4	8.5	6.7	
66	770.21	R	30.0	29.1	28.3	2.65	17.2	11.8	8.7	
67	770.59	R	31.3	30.3	29.5	2.64	73.1	37.8	25.0	
68	770.88	R	31.7	30.6	29.8	2.66	31.1	22.0	17.7	
69	771.28	R	31.3	30.4	29.4	2.69	30.4	21.0	16.1	
	MEAN		**30.1**	**29.4**	**28.9**	**2.8**	**30.6**	**22.9**	**18.9**	**GFU6**
	Std DEV.		**6.9**	**6.7**	**6.5**	**0.2**				
70	771.60	R	11.7	11.7	11.6	3.13	0.13	0.13	0.12	SB6
71	771.90	R	34.7	33.8	33.1	2.69	76.5	63.9	56.5	
72	772.21	R	34.8	34.1	33.3	2.67	73.2	59.8	52.6	
73	772.58	R	35.9	34.8	34.1	2.66	107	72.3	57.7	
74	772.91	R	36.7	35.7	34.9	2.71	189	140	113	
75	773.20	R	35.3	34.5	34.0	2.69	78.6	64.9	58.0	
76	773.59	R	34.5	33.8	33.1	2.71	70.6	53.9	46.7	
77	773.90	R	34.7	34.0	33.3	2.68	79.8	67.0	59.6	
78	774.26	R	33.4	33.1	32.8	2.76	124	118	113	
79	774.52	R	39.1	38.5	38.0	2.70	523	471	434	
	MEAN		**35.5**	**34.7**	**34.1**	**2.7**	**114.0**	**92.7**	**81.2**	**GFU7**
	Std DEV.		**1.6**	**1.6**	**1.6**	**0.0**				
80	774.89	R	35.5	34.9	34.5	2.66	186	168	155	SB7
81	775.20	R	35.6	34.8	34.3	2.66	163	137	119	
82	775.63	R	38.9	37.7	36.9	2.73	498	389	319	
83	775.91	R	36.7	36.0	35.5	2.66	356	294	258	
84	776.24	R	36.6	35.9	35.4	2.65	304	263	238	
85	776.60	R	36.4	35.8	35.3	2.66	308	279	256	
86	776.90	R	37.0	36.0	35.3	2.79	464	371	318	
87	777.19	R	36.4	35.9	35.4	2.65	327	294	272	
88	777.60	R	34.9	34.4	34.0	2.66	297	272	257	
89	777.90	R	35.9	35.2	34.8	2.65	358	320	297	
90	778.20	R	35.8	35.1	34.7	2.66	328	297	280	
91	778.63	R	35.7	35.1	34.7	2.65	311	279	260	
	MEAN		**36.4**	**35.6**	**35.1**	**2.7**	**326.2**	**282.2**	**254.2**	**GFU8**
	Std DEV.		**1.0**	**0.9**	**0.8**	**0.0**				

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PATRICIA-1 CORE DATA

CORE DATA SET DISCRIMINATED TO MATCH DIFFERENTIATION CARRIED OUT ON LOGS FOR RESERVOIR/SIDERITE DIFFERENTIATION

Klinkenberg Correction from Baleen-2 data:			
If Amb. Perm <	100	apply factor	0.815
If Amb. Perm = >	100	apply factor	0.905

	Patricia Core Data		Ambient			Stress Permeability		
Core No.	Patricia-1	Depth	Porosity	Permeability	Klinkenberg Corrected	0.765	Grain Density	
1	1	703.30	35.1	72	59	45	2.66	
1	2	703.60	35.7	110	100	76	2.65	
1	5	704.50	35.1	166	150	115	2.65	
1	7	705.10	36.7	254	230	176	2.65	
1	8	705.40	32.4	16	13	10	2.68	
1	9	705.70	37.7	137	124	95	2.64	
1	11	706.30	39.1	676	612	468	2.66	
1	12	706.60	31.8	99	81	62	2.66	
		Mean	**35.5**	**122**	**106**	**81**	**2.66**	**GFU2**
		Std Dev.	**2.5**				**0.01**	
1	13	706.90	37.6	350	317	242	2.65	
1	14	707.20	38.7	107	97	74	2.68	
1	15	707.50	27.6	45	37	28	2.79	
1	16	707.80	38.9	645	584	447	2.64	
1	17	708.10	37.6	213	193	147	2.71	
1	18	708.40	34.9	687	622	476	2.66	
1	19	708.70	35.7	530	480	367	2.67	
1	21	709.30	37.3	458	414	317	2.67	
		Mean	**36.0**	**281**	**251**	**192**	**2.68**	**GFU3**
		Std Dev.	**3.7**				**0.05**	
1	22	709.60	41.6	234	212	162	2.70	
1	23	710.20	38.5	530	480	367	2.65	
1	24	710.50	38.8	313	283	217	2.66	
1	25	710.80	38.3	243	220	168	2.72	
1	26	711.10	39.1	424	384	294	2.63	
1	27	711.40	34.9	149	135	103	2.64	
1	28	711.70	36.1	117	106	81	2.66	
1	30	712.30	41.0	624	565	432	2.64	
1	31	712.60	36.9	238	215	165	2.67	
		Mean	**38.4**	**279**	**253**	**193**	**2.66**	**GFU4**
		Std Dev.	**2.2**				**0.03**	
1	32							
1	33							
1	34	713.50	38.5	250	226	173	2.71	
1	35	713.80	38.1	271	245	188	2.69	
		Mean	**38.3**	**260**	**236**	**180**	**2.70**	**GFU5**
		Std Dev.	**0.3**				**0.01**	
1	36	714.10	16.0	1	1	0	3.07	
1	37	714.40	34.6	87	71	54	2.74	
1	38	714.70	34.1	107	97	74	2.74	
1	40	715.30	32.0	96	78	60	2.89	
1	41	715.60	35.6	199	180	138	2.85	
1	42	715.90	19.6	7	6	4	3.10	
		Mean	**28.7**	**32**	**27**	**20**	**2.90**	**?SB5**
		Std Dev.	**8.6**				**0.16**	
1	43	716.20						
1	44	716.50	35.1	215	195	149	2.78	
1	45	716.80						
1	46	717.10						
1	47	717.40	36.6	330	299	228	2.69	
1	50	718.30	38.3	235	213	163	2.71	
1	51	718.60						
1	52	718.90	38.5	201	182	139	2.73	
1	53	719.20	43.3	239	216	165	2.67	
1	54	719.50	42.6	350	317	242	2.70	
1	55	719.80	41.6	319	289	221	2.66	
1	56	720.10	40.3	530	480	367	2.71	
1	57	720.40						

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2	71	725.30	35.8	48	39	30	2.69	
2	72	725.60						
2	73	725.90	35.5	39	32	24	2.71	
		Mean	**35.9**	**67**	**57**	**44**	**2.70**	**GFU6**
		Std Dev.	**4.1**				**0.04**	
2	74	726.20	36.7	40	33	25	2.73	
2	75	726.50	33.9	51	42	32	2.67	
2	76	726.80	35.2	72	59	45	2.78	
2	77	727.10	36.1	46	37	29	2.74	
2	78	727.40	36.9	46	37	29	2.70	
2	79	727.70	34.7	51	42	32	2.81	
		Mean	**35.6**	**50**	**41**	**31**	**2.74**	**GFU7**
		Std Dev.	**1.2**				**0.05**	
2	81	728.30	37.4	216	195	150	2.74	
2	82	728.60	31.4	81	66	51	2.65	
2	83	728.90	35.4	55	45	34	2.65	
2	84	729.20	35.3	69	56	43	2.63	
2	85	729.50	35.1	95	77	59	2.66	
2	86	729.80	36.4	221	200	153	2.67	
2	87	730.10						
2	88	730.40	32.5	142	129	98	2.66	
2	91	731.30	35.4	162	147	112	2.61	
2	92	731.60						
2	93	731.90	35.1	168	152	116	2.62	
2	94	732.20	31.5	125	113	87	2.59	
2	96	732.80	34.4	117	106	81	2.65	
2	97	733.10	34.9	181	164	125	2.62	
2	98	733.40	38.1	279	252	193	2.65	
2	99	733.70	33.8	214	194	148	2.68	
2	101	734.30						
		Mean	**34.8**	**137**	**121**	**92**	**2.65**	**GFU8**
		Std Dev.	**2.0**				**0.04**	
2	102	734.60	35.0	386	349	267	2.66	
2	103	734.90	35.0	222	201	154	2.65	
2	104	735.20	38.0	160	145	111	2.72	
2	105	735.50	32.5	46	37	29	2.78	
2	106	735.80	34.1	43	35	27	2.68	
2	107	736.10	34.8	75	61	47	2.65	
2	108	736.40	33.8	84	68	52	2.68	
2	109	736.70	31.1	68	55	42	2.56	
2	112	737.60						
2	113	737.90	34.9	41	33	26	2.70	
2	114	738.20	36.4	46	37	29	2.66	
2	115	738.50	33.2	43	35	27	2.71	
		Mean	**34.4**	**81**	**68**	**52**	**2.68**	**GFU9**
		Std Dev.	**1.9**				**0.05**	
2	116	738.80	15.4	0	0	0	3.14	
2	117	739.10	22.4	0	0	0	3.14	
2	118	739.40	20.5	1	0	0	3.05	
2	119	739.70	26.7	3	3	2	2.87	
3	121	740.30	33.3	36	29	22	2.66	
3	122	740.60	26.5	37	30	23	2.79	
3	123	740.90	28.5	31	25	19	2.84	
3	124	741.20	31.0	21	17	13	2.83	
3	125	741.50	8.0	0	0	0	4.42	
3	127	742.10	32.7	112	101	78	2.72	
3	128	742.40	30.8	48	39	30	2.76	
3	129	742.70	32.7	11	9	7	2.62	
		Mean	**25.7**	**4**	**3**	**2**	**2.99**	**BCZ**
		Std Dev.	**7.8**				**0.48**	

Appendix C FWL Estimate and RFT Pressure analysis

1.0 Free Water Level (FWL)

1.1 Original FWL

'Initial' reservoir pressure data from Spermwhale-1, Whale-1 and Baleen-1 wells was used to estimate an 'original' FWL for the Patricia Baleen field.

Pressure data from Patricia-1, drilled in 1987, is not considered suitable for estimating an original FWL as it is likely that this well has undergone pressure depletion and is not at initial conditions.

Aquifer pressure data from the Latrobe Coarse Clastics exists for both Spermwhale-1 and Whale-1, both drilled in 1981. This pressure data has a near perfect match (Figure A1) with the 'original Gippsland Basin pressure data' for the regional aquifer[1]. Hence the Latrobe Coarse Clastics aquifer is considered to be 'undepleted' in 1981.

On the assumption that the Gurnard and the Latrobe Coarse Clastics have a common aquifer and their respective gas legs were originally in pressure equilibrium, it is reasonable to believe that the 1981 Gurnard gas leg pressures in the Baleen-1 well are at initial conditions (or are quite close to original pressures).

An 'original' FWL estimate of 735.6m ss is derived from a gradient intercept technique using the aquifer pressure data from both Spermwhale-1 (1981) and Whale-1 (1981) wells with the gas leg pressure data from Baleen-1 (1981).

1.2 1987 FWL

The pressure depletion in Patricia-1 (1987) well is due to the production offtake in the main Bass Strait area.

For the Latrobe Coarse Clastics a 1987 FWL at 729m ss was determined from a gradient intercept technique using the water and gas leg depleted pressure data from the Latrobe Coarse Clastics in the Patricia-1 well.

The 1987 FWL of the Gurnard formation can only be estimated within a range as the Patricia-1 well has only gas leg pressure data in the Gurnard. This FWL range lies between 725m ss and 734m ss.

The 734m ss is a result of a gradient intercept between the Gurnard gas pressure gradient and the Latrobe Coarse Clastics water pressure gradient in Patricia-1. The 725m ss is a result of a gradient intercept between the Gurnard gas pressure gradient from Patricia-1 and the original regional water pressure gradient.

It is observed that the Gurnard has not undergone as much depletion as the Latrobe Coarse Clastics.

The 1987 FWL estimate for the Latrobe Coarse Clastics is 729m ss.

1.3 1999 FWL

For the Gurnard a 1999 FWL at 738.2m ss was determined from a gradient intercept technique using the water and gas leg depleted pressure data from the Gurnard in the Baleen-2 well. This

[1] It is noted that the water gradient used in the estimate of the FWL at 735.6m ss is also supported by an actual measured gradient of a Baleen-2 water sample.

suggests that the original FWL has been pushed down 2.6m between 1981 and 1999 possibly due to the lowering of pressure in the regional aquifer. The full pressure regime will be looked at in depth taking account of the spill point picks from the ongoing 3-D seismic work and will from part of the final field development plan submission.

Water gradients in the Gurnard Fm and Latrobe Group Coarse Clastics at Baleen-2 are the same within the limitations of the measurements and a common salinity has been assumed for both formations.

2.0 Pressure

In the six years between 1981 (Baleen-1) and 1987 (Patricia-1) 15psi depletion has been observed in the gas leg of the Gurnard Formation. An additional 23psi depletion occurred in the Gurnard Formation over the next 12 years between 1987 (Patricia-1) and 1999 (Baleen-2). Over an 18-year period there is a drop of 38psi in the Baleen-1 pressure of 1105psi to 1067psi (datum 680m ss) since 1981.

The depletion is a result of production from the underlying Latrobe hydrocarbon reservoirs to the south, which have in turn depleted the massive Latrobe aquifer. It is expected that the rate of pressure depletion in Patricia Baleen is primarily dependent on the magnitude of the difference in the Esso(BHP)'s volume offtake rate and the regional aquifer charge rate.

From pressure data the Latrobe Group Coarse Clastics pressure regime is lower than Gurnard Formation by 2psi in Baleen-1 (1981), 6psi in Patricia-1 (1987) and 6-8psi in Baleen-2. It is expected that the interface boundary between the Gurnard Formation and the Latrobe Group Coarse Clastics will act as a barrier to any aquifer influx from the Latrobe Group Coarse Clastics.

A gas gradient of 0.072psi/m and a water gradient of 1.41psi/m is estimated for both the Gurnard and Latrobe Coarse Clastics based on well pressure data and supported by PVT data.

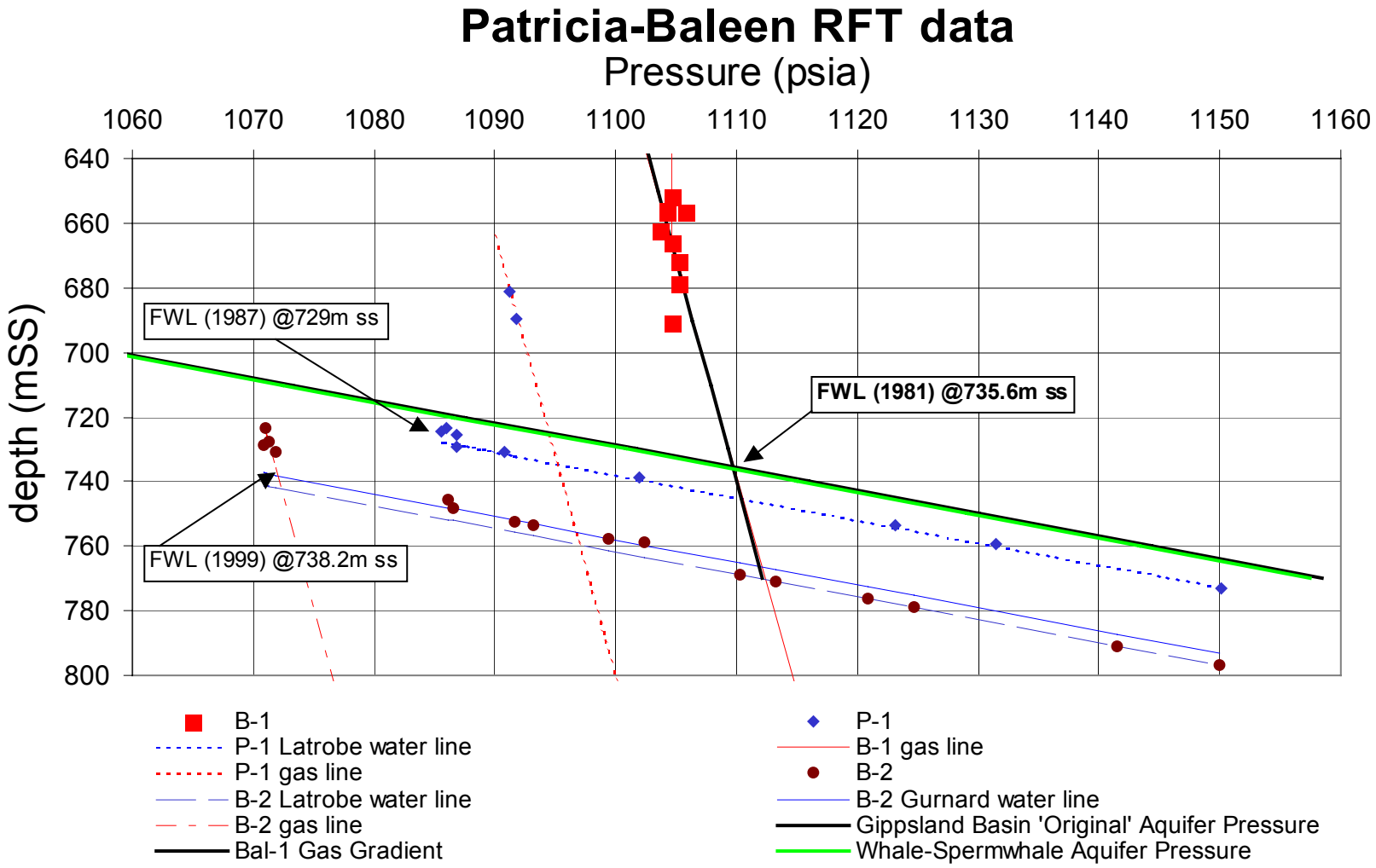

Patricia-Baleen RFT data
Pressure (psia)
1060
1070
1080
1090
1100
1110
1120
1130
1140
1150
1160
depth (mSS)
640
660
680
700
720
740
760
780
800
FWL (1987) @729m ss
FWL (1981) @735.6m ss
FWL (1999) @738.2m ss
B-1
P-1 Latrobe water line
P-1 gas line
B-2 Latrobe water line
B-2 gas line
Bal-1 Gas Gradient
P-1
B-1 gas line
B-2
B-2 Gurnard water line
Gippsland Basin 'Original' Aquifer Pressure
Whale-Spermwhale Aquifer Pressure

FIGURE A1

APPENDIX D ECLIPSE MODEL DESCRIPTION

1.0 Reservoir Model

1.1 Top of Model

A 50m x 50m mesh file of the top of Gurnard Formation was generated based on 3-D seismic depth maps. This was input to Eclipse GRID as the top surface of the model.

1.2 Vertical Layering and Base of Model

The Gurnard Formation was divided into 16 layers based on well log (Baleen 1, Patricia 1 & Baleen 2) correlations and core data (Patricia 1 & Baleen 2) correlations. Good correlation exists between the wells.

The low permeability siderite bands, seen on the well logs sandwiched between the sand layers, were modelled as individual layers. This enabled the Eclipse model to be used determine the sensitivity analysis of the GIIP and the recoverable volumes based on the formation properties of the siderite bands.

Sixteen individual layer maps were generated from contouring the layer thickness as measured at the three well locations. The gross reservoir thickness map from combining the sixteen layers was corrected to honour the gross thickness observed from the good quality 3-D seismic data. This correction factor was applied equally to each of the layer thickness contour maps such that the gross thickness from combining the corrected maps matched very closely to the gross thickness map from the 3-D seismic depth map. The sixteen corrected individual layer maps were each stacked below the top of structure map to formulate the reservoir architecture.

1.3 Grid Dimension

The model has a 42 x 32 x 16 grid (21,504 grid blocks), which covers the entire hydrocarbon bearing areas of interest (Figure D1). The smallest grid block size is about 100m x 100m in the vicinity of the wells, and the largest cells in the flank area are close to 500m x 500m. The reason for choosing a fine grid is to model the well performance as accurately as possible. The vertical section consisted of 16 layers.

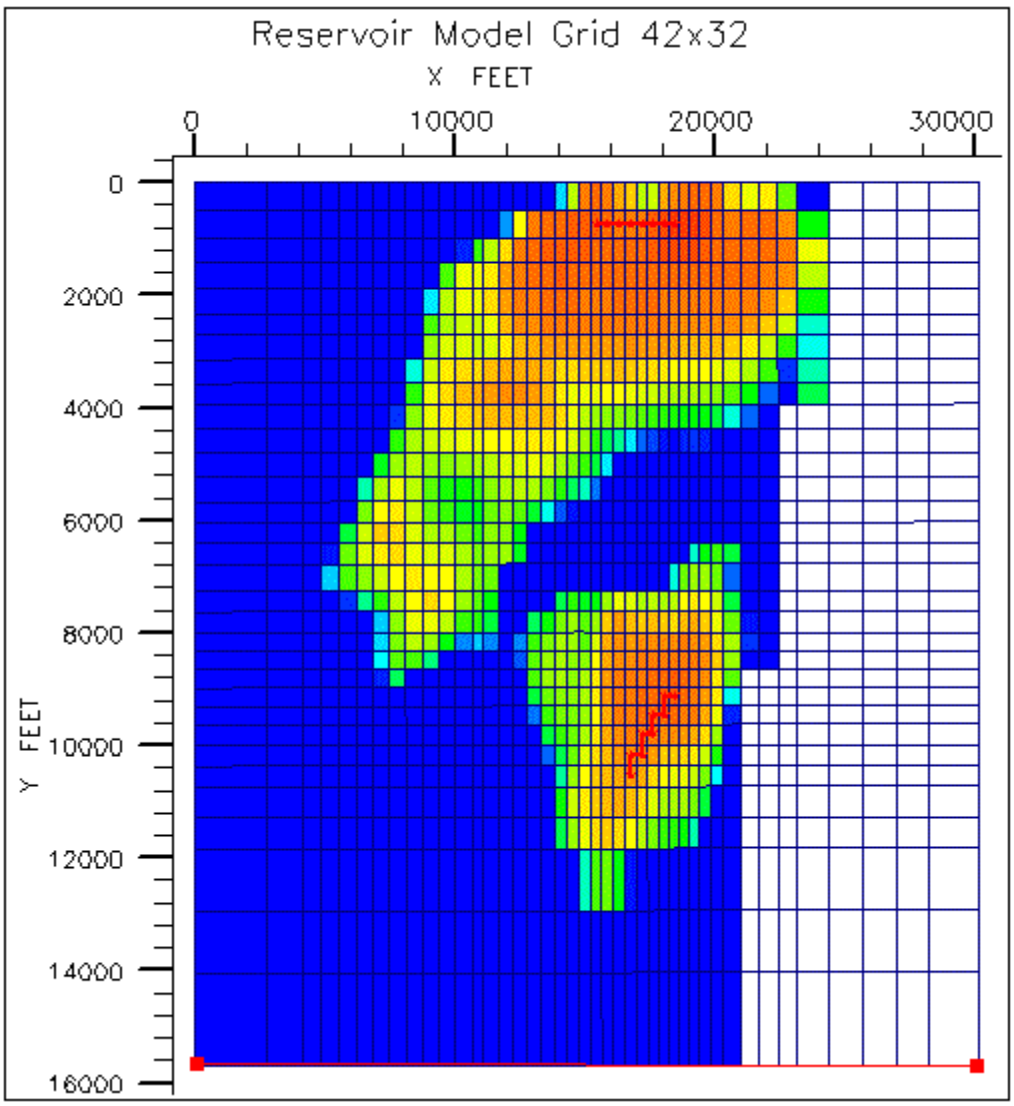


Figure D1

The 3-D model was initialised with the original GWC at 738.2 m. SS in Baleen and 730 m SS in Patricia.

The model has a gross rock volume of 277 x $10^6 m^3$, which is in good agreement with the geophysics' estimate of 269 x $10^6 m^3$ from the 3-D seismic data.

1.4 Faults and Flow Barriers

The faults along the north and northwest flanks of the Baleen structure are deemed no-flow boundaries (Fig D1). Other faults are most probably partially or non-sealing due to small throws. The transmissibility across the internal faults was assumed to be unity and then reduced for the sensitivity runs.

1.5 N/G, Porosity and Permeability

The areal distribution of the porosity, net to gross, and permeability per layer were interpolated based on the assigned layer properties at the three wells determined from core and log data (see Appendix B).

The air permeabilities were corrected by a factor of 0.32 in Gurnard flow units. This correction was necessary to conform to insitu kh measurements from DST's conducted in Baleen 1 and Patricia 1 (see table below).

Well	Test	Zone (mRT)	MMscf/d	FFBHP (psia)	Kh (mD-ft)	K (mD)	S
Baleen 1 Gurnard	DST 2A	662-670	6.3	670	2,100	60	3.6
Patricia 1 Gurnard	DST 3A	703-738	24.1	774	2,625	22	0.9

1.6 Saturation Functions

Three rock types were modeled based on SCAL results from Baleen 2. As is normally the case, there is a good relationship between Swir and permeability; Swir's being lower for the higher permeability rock (Fig D2). The higher permeability layers were assigned rock type 1; intermediate quality rock type 2 and the siderite layers were assigned rock type 3.

The J-curve methodology for averaging capillary pressure curves was not applied since this method is considered unsuitable when the range of permeability (0.02 to 300 mD) and Swir (30 to 46) is relatively wide.

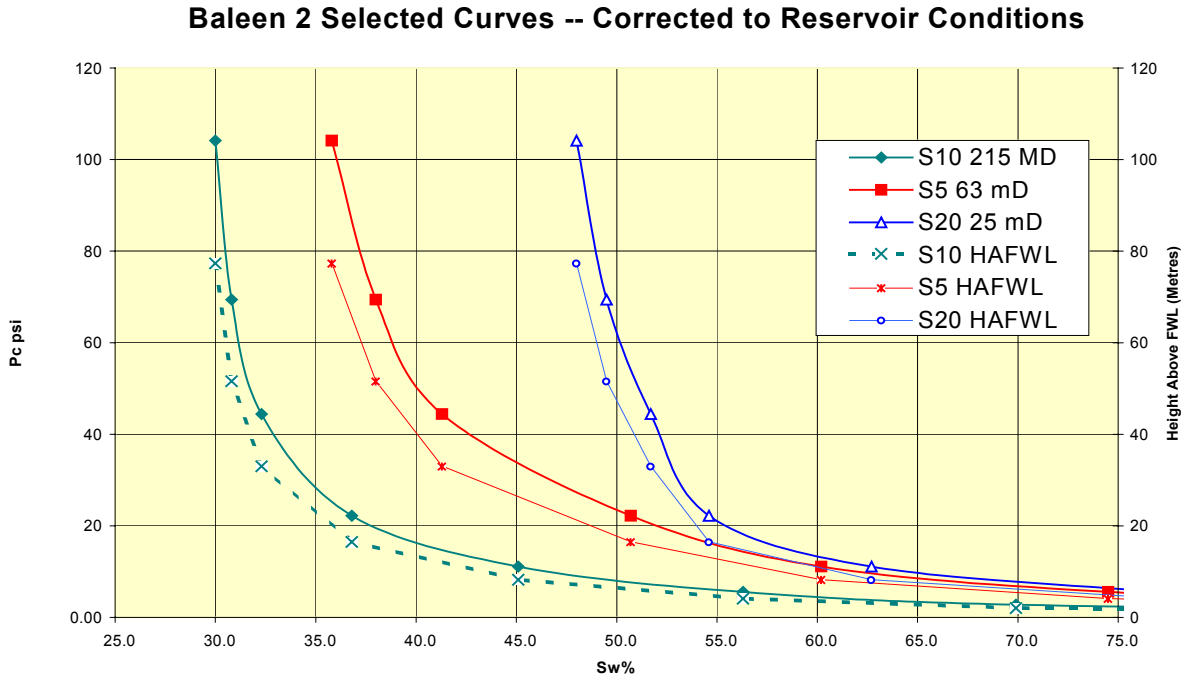
A GWC of 738.2m SS was estimated for the Baleen structure and 730.0m SS for the Patricia structure (Section 3.1.3 and Appendix C).

The individual layers were assigned a rock type based on average layer permeability as follows:

S_{wir}	SCAL Sample & Permeability	Permeability Range mD	Model Layer
Rock Type 1 -- 30%	S10 – 215 mD	>90	3, 5, 13
Rock Type 2 -- 35%	S5 – 63 mD	40-90	1, 7, 9, 11, 15
Rock Type 3 -- 46%	S20 – 25 mD	0.02-40	2, 4, 6, 8, 10, 12, 14, 16
Siderite Layers			

The gas saturation of the layers and the transition zone were defined by the capillary pressure curves.

Figure D2



1.7 GIIP Results

The GIIP in the areas of interest were estimated to be 63.3 Bscf (Baleen) and 21.3 Bscf (Patricia), giving a total GIIP of 84.6 Bscf.
The individual layer gas-in-place volumes are presented below; layer 1 being the top layer.

Layer	1	3	5	7	9	11	13	15	Siderite Layers 2, 4, 6, 8, 10, 12, 14, 16	Total
GIIP (Bscf)	15.9	13.1	12.7	3.3	13.9	4.2	6.4	3.7	11.4	84.6

1.8 Relative Permeability

Residual gas saturations were measured by special core analysis to be about 16%. However, these were considered unrealistically low and were adjusted to 25%. The relative permeability curves were generated with Corey exponents of 2.0 for gas and 4.0 for water. The relative permeability curves for the three rock types are shown in Figs D3 to D5 . These assume Swc = Swir viz 0.30, 0.35 and 0.46 for each of the three rock types.

Figure D3

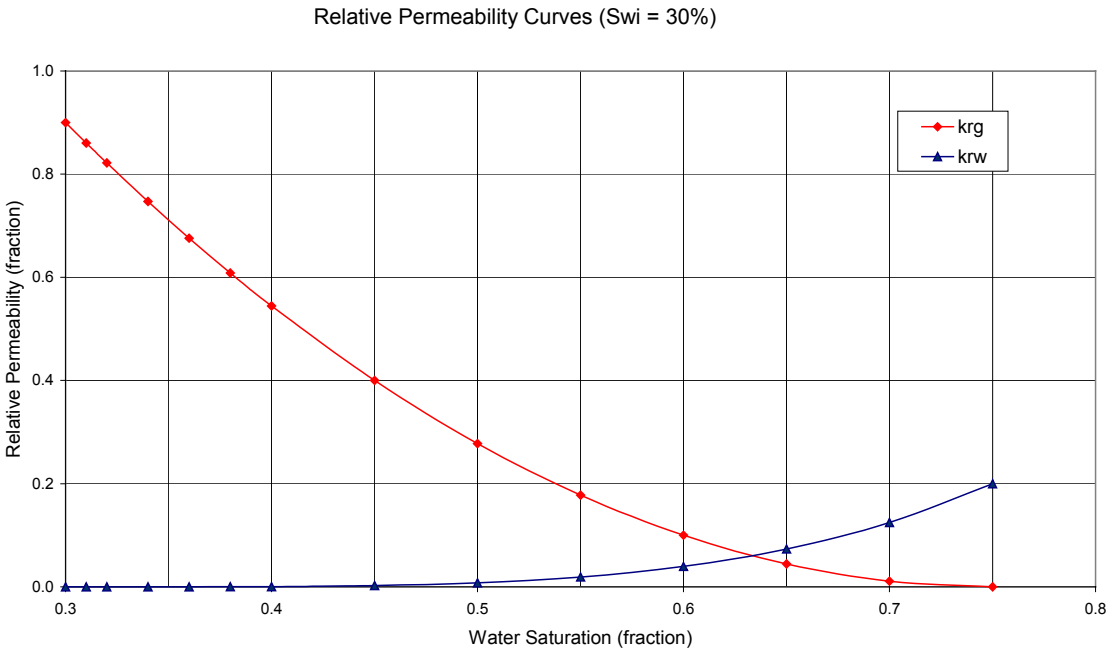


Figure D4

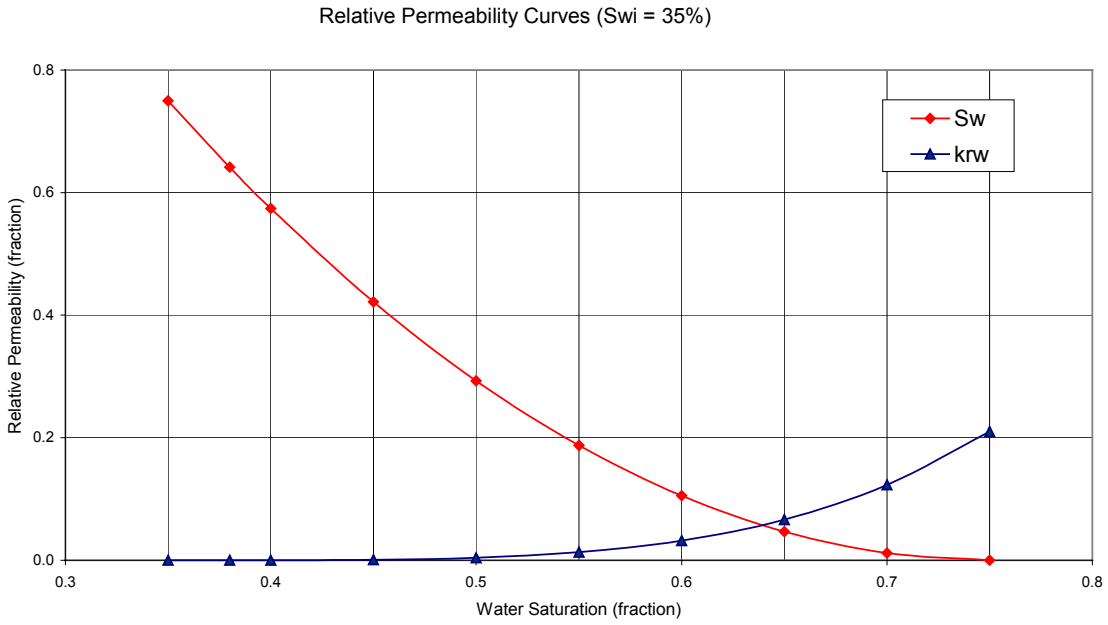
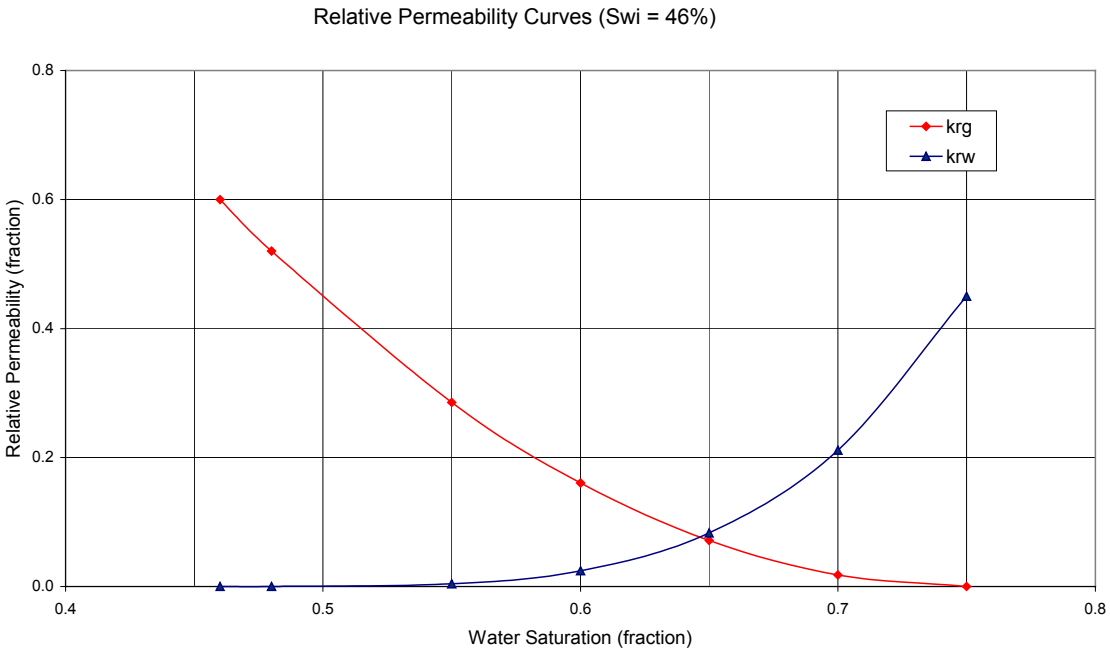


Figure D5



1.9 PVT Data

The gas consists of close to 98% pure methane and contains insignificant quantities of NGL and condensate. The gas properties were obtained using the equation of State (EOS) based on a gas sample collected during the Patricia 1 well test.

Component	Methane	Ethane	Propane	i-Butane	n-Pentane	Hexane+	Nitrogen	CO2
Mole %	97.724	0.28	0.005	0.003	0.003	0.005	0.66	1.32

A gas expansion factor of 72.4 scf/rcf was calculated based on the above gas composition. The gas has a heating value of 36.86 MJ/m^3, which equates to 1.0438 PJ/Bscf.

1.10 Aquifer

It is expected that the Gurnard Formation in both the Baleen and Patricia accumulations will have weak to no aquifer support. This expectation is based on the geometry of the structure and the relatively low permeability nature of the reservoir.

1.11 Well Locations

The optimised development has two wells, one each in the Baleen and Patricia structures

1.12 Vertical and Horizontal Tubing/Pipeline Performance

Gray's correlation was used for vertical lift performance modelling based on a review of industry standard vertical lift performance correlations for similar field developments (Reference "Patricia-Baleen Vertical Lift Performance and Multiphase Flow Correlation Review", July 2000 by Helix Well Technologies).

This correlation is proven for low-pressure gas field developments and is also less conservative than the Beggs and Brill correlation. Studies by the Mobil Research Development Centre (MRDC), Shell and American Petroleum Association (APA) have

concluded that the MMS (Moreland/Mobil/Shell) oil correlation and the Gray gas correlation are the most universally applicable correlations.
The Beggs and Brill correlation was used for modelling horizontal flow including the near horizontal section of the two wells and the flowlines. This correlation is known to be relatively conservative and was selected in the absence of "real" calibration data. Gray's correlation was used for vertical flow in the wells.

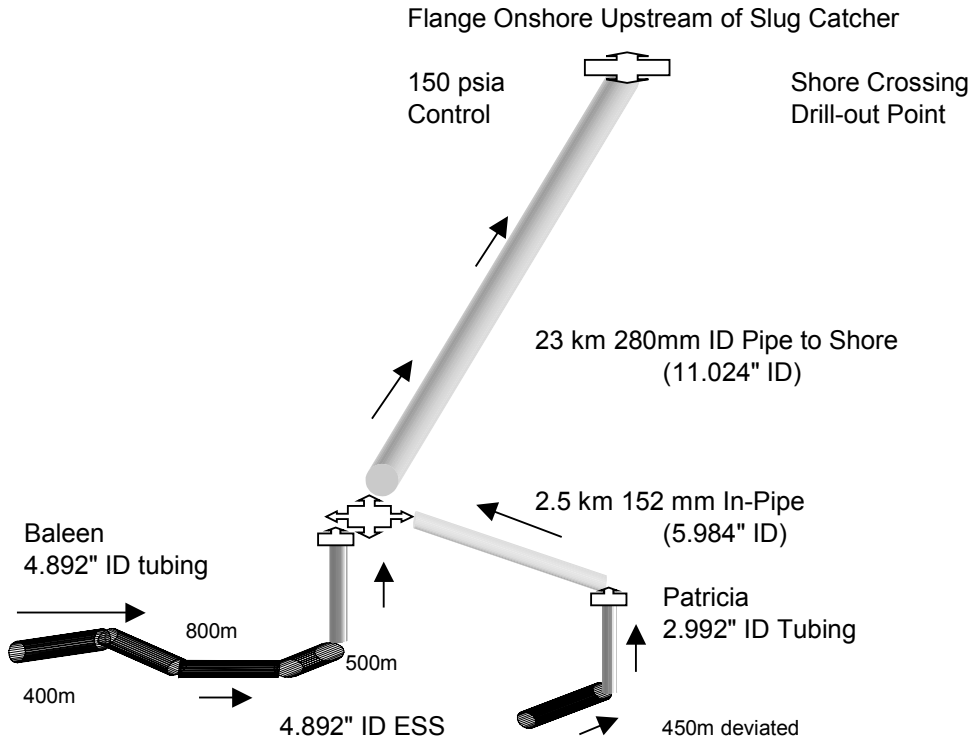
2.0 Network Model

A network model was built. The benefit of a network model allow individual well productivity to be modelled more accurately allowing for any well back-out components and the use of more accurate volumes through the pipeline to shore.

The network model (Fig D6) for a two-well case with the sub-sea manifold located at the Baleen wellhead was set up using the VFP_i and Geoquest module.

The Baleen well was assumed to be 500m at 80° in a structurally high culmination, followed by 800m horizontally towards an adjoining culmination with a further 400m horizontal section in this culmination. The well was completed with 4.892" ID tubing. A 2.5 km 5.984" ID in-line was assumed from the Patricia well which was modelled as an 80° 450m well with 2.992" ID tubing. Expandable Sand Screens with 4.89" ID were assumed for both wells. The manifold was connected to flange upstream from slug catcher at drill-out point onshore via a 23km 11.024" ID (280mm) pipeline.

Figure D6



2.1 Wellbore Skin

A skin factor of 5.0 was applied to the wells to account for potential wellbore pressure losses associated with expandable sand screens (ESS). The DST analyses in Baleen 1 and Patricia 1 indicate that formation damage was negligible, and the pressure drop due to turbulent flow was small.

2.2 Tubing Size

The tubing sizes for the Baleen well and the Patricia well are 5 ½" OD tubing (4.892" ID) and 3 ½" OD tubing (2.992" ID) respectively.

2.3 Plant Capacity

A plant capacity of 50 MMscf/d was selected.

2.4 Plant Inlet Pressure

The base case Plant inlet pressure is 150 psia. The commercial robustness of 150 PSI was determined from simulation.

2.5 Reserves Results

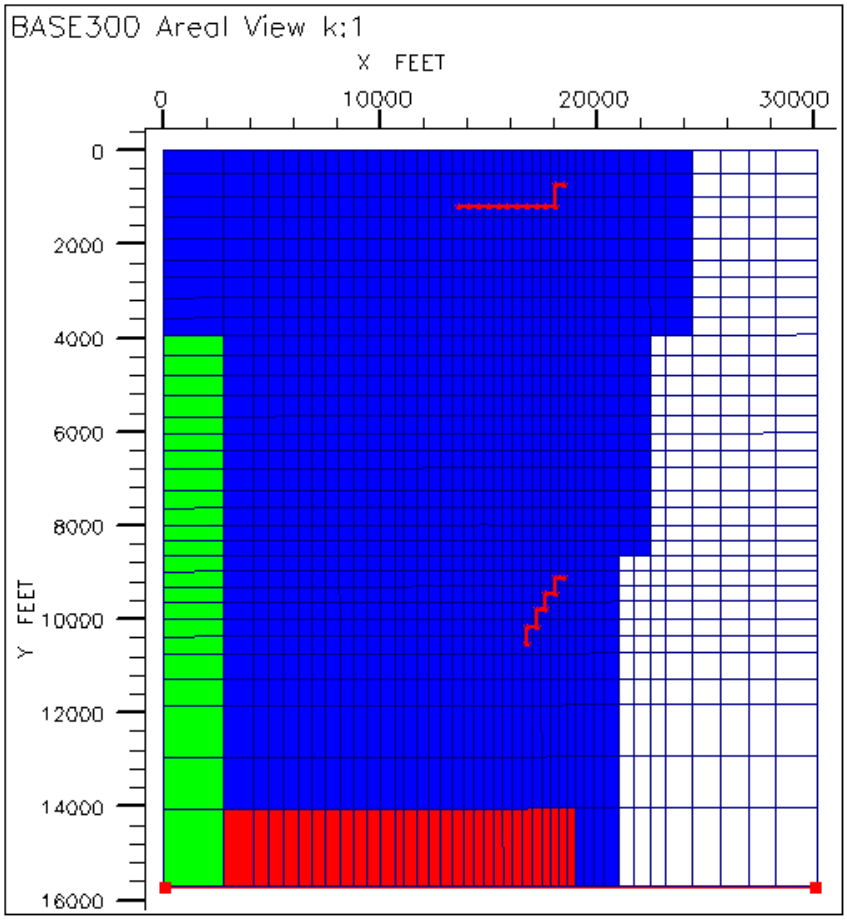
The reserves in the areas of interest were estimated to be 44.3 Bscf (Baleen) and 14.9 Bscf (Patricia), giving total reserves of 59.2 Bscf.

APPENDIX E AQUIFER SENSTIVITIES

1.1 Patricia-Baleen Aquifer Sensitivities

Sensitivity to aquifer support was investigated by running a case with an infinite acting aquifer connected to a 500 mD row of grids assuming a 90° angle subtended by the boundary between the reservoir and the aquifer (Figure E1).

Figure E1



Figures E2 and E3 show the layer 5 initial and resultant water saturation after eight years of production. The Patricia culmination is more impacted by aquifer influx than the Baleen culmination.

Figure E2

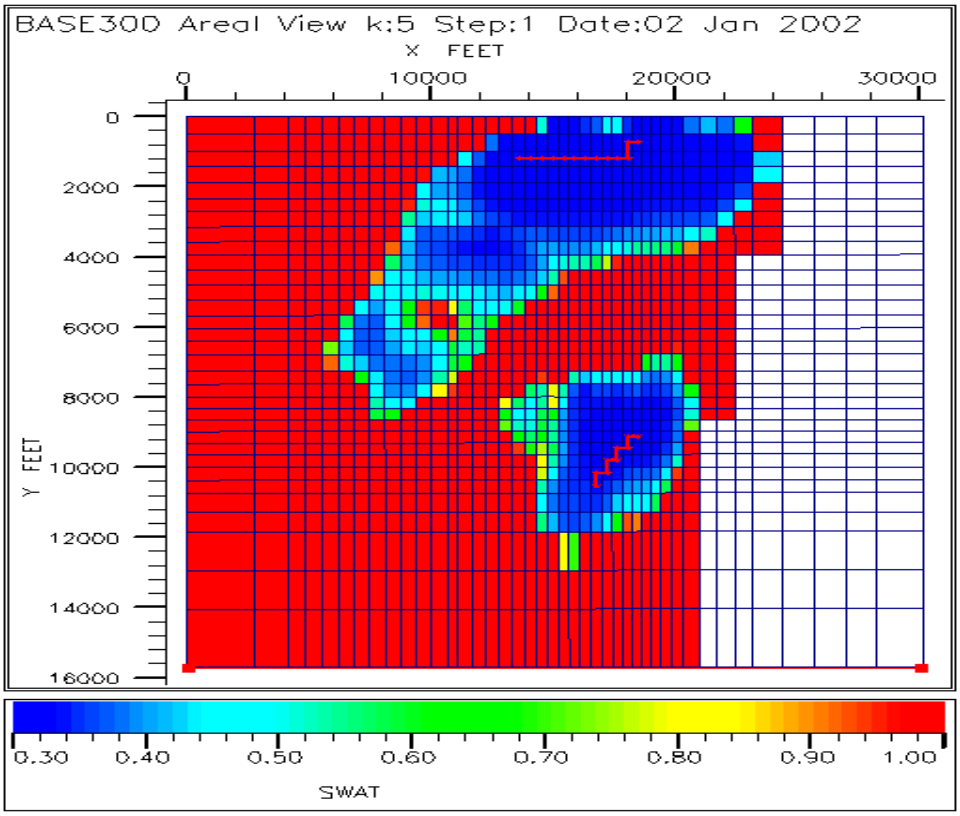
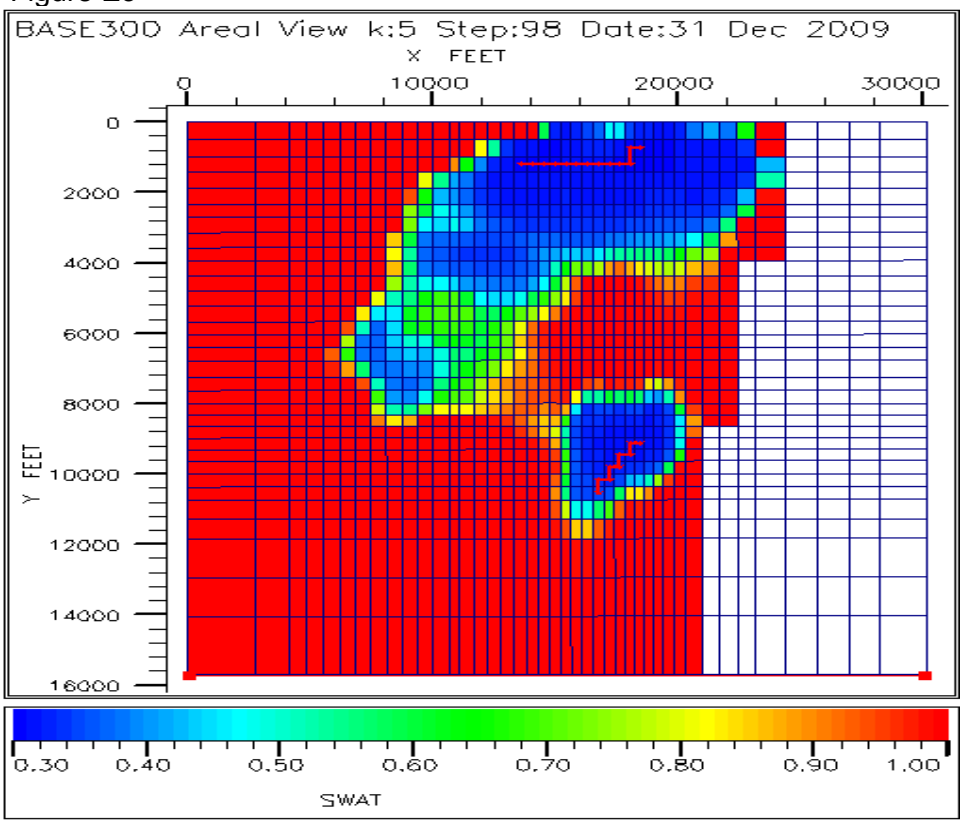


Figure E3



Results show that the infinite aquifer does not significantly change well gas rates or reserves. Nonetheless, maximum formation water production rates at the Patricia well increased from 70 to 100 stb/d (Figure E5). No formation water was predicted in either case for the Baleen well.

Figure E4 Field Performance Base Case vs Infinite Aquifer Case

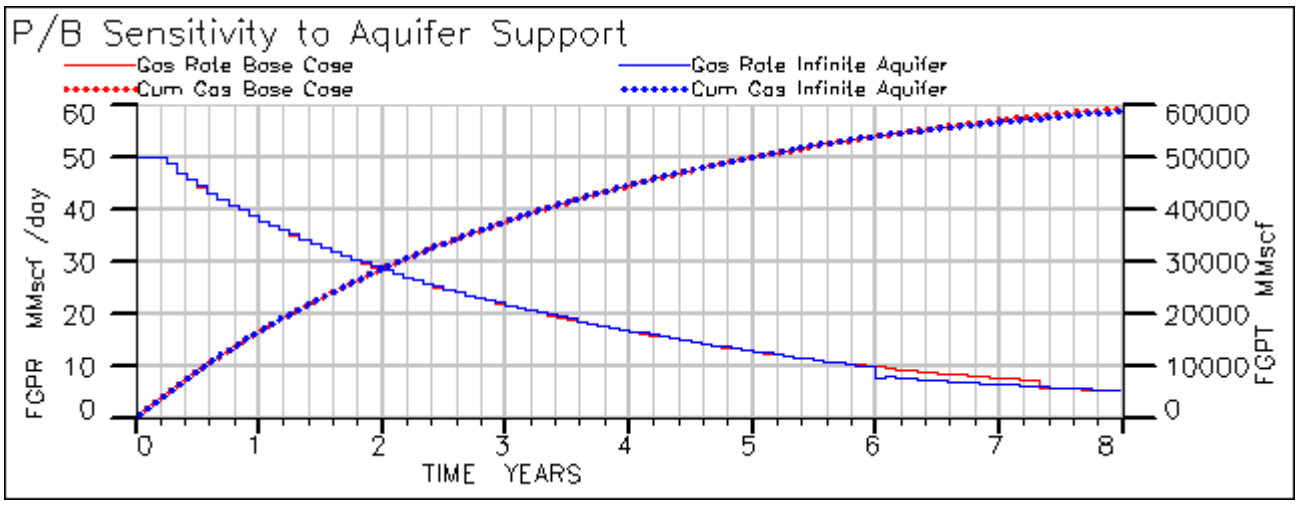
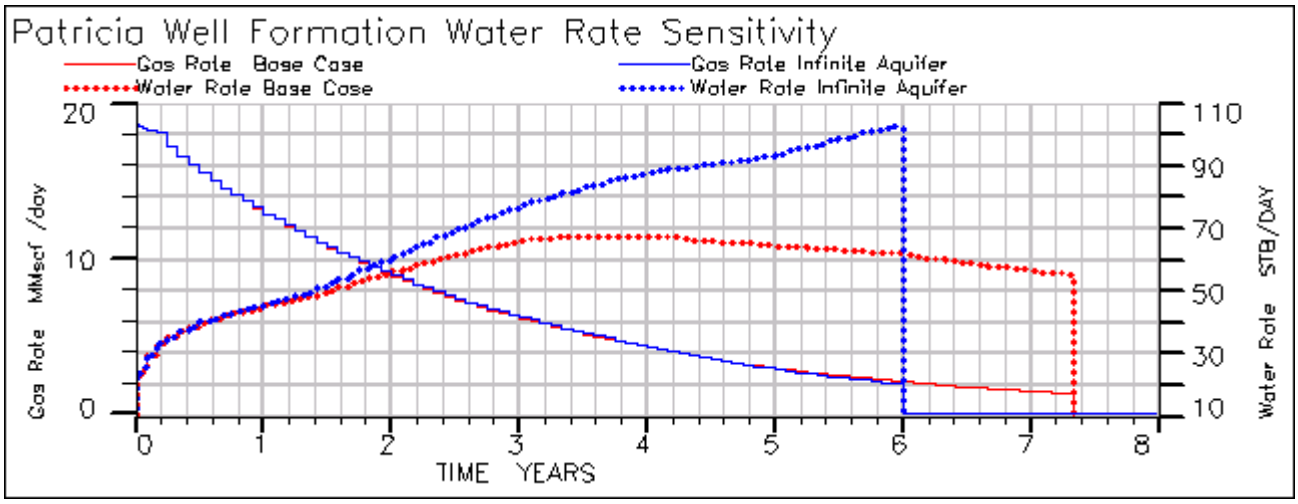


Figure E5 Patricia Well Formation Water Production as a function of Aquifer Volume



APPENDIX F PATRICIA-BALEEN DST RESULTS

1.0 Overview

1.1 Well Performance and Testing

Drill stem tests (DST) were carried out on both the Latrobe Group Coarse Clastics and the Gurnard Formations in Baleen -1 and Patricia -1.

Latrobe

Both DST tests on the Latrobe Group Coarse Clastics in Patricia-1 and Baleen-1 had technical problems making it difficult to interpret formation characteristics such as permeability and skin. However flowrates of 1.8 MMscf/d and 2.6 MMscf/d on a 1" choke was recorded for the Baleen-1 and Patricia-1 wells respectively with up to 75ppm H_2S reported in the Patricia-1 gas.

Gurnard

The Gurnard formation tested at 6.3 MMscf/d on a 1" choke in Baleen-1 and at 24.5 MMscf/d on a 1.25" choke in Patricia-1 with no H_2S reported.

In some of the DST tests the interpretation of skin and Kh from the drawdown and build-up data was compromised by the quality of the data and the procedures employed (Appendix C). However the DST test #2 and DST test #3A of Baleen-1 and Patricia-1 were considered to be of good quality.

2.0 DST Interpretation Summaries

The following sumarises the analysis carried out on DST interpretations over the years by various companies.

2.1 Baleen –1 DST #1 (700 – 706 mRT)

Latrobe coarse clastics - One main flow followed by buildup. Main flow test was not interpretable (early rates not measured)

Blumer Associates

k = 89 md , S = 130-140. Results are questionable.

Lasmo (1988)

Straight-line slope on Horner plot was difficult to identify.
Assumed skin similar to Gurnard formation. Av. k = 16 md

Comments

In both analyses, the early buildup was dominated by wellbore storage, which was not properly evaluated. Pressure derivative plots should be used. Analysis of the BU was uncertain because the pressure rapidly builds up to a maximum value and remains flat. This could be due to the presence of a nearby constant pressure boundary, which was not supported by geological evidence.

2.2 Baleen –1 DST #2 (660 – 670 mRT)

Gurnard Formation – One main flow followed by buildup

Blumer Associates

BU analysis with straight Horner plot (no superposition time function) yields k = 27 md, S = +19.4 (h = 12.5 m)

BU was reanalyzed with Horner plus time superposition, but with two values for sand thickness, h = 12.5 and 34.2 to include the bottom part of the Gurnard below the shale which was not perforated.

Results were k = 16.6 – 18.7 md.
Skin factor was determined separately from the early time region for h = 12.5m and late time region for h = 34.2 m.

S = +3.2 for early time and +18.4 for late time.

It was concluded that the shale break below the perforations did not extend far beyond the well, and that the higher skin was due to partial penetration effect.

An attempt to use Type Curves was unsuccessful.

Lasmo
Lasmo interpreted the test in 1981 and 1988. In 1981 only the p^2 method was used. In 1988 the pseudo pressure method was also used in addition to the p^2 method. The results were similar, i.e.
1981 k = 56 md, S = +18.3
1988 k = 51 md, S = +17.0
The above results were obtained from BU data. In 1988, the flow tests were also analysed which gave similar permeability, but higher skin factors (+22 to +26).

Lasmo determined the AOF by plotting $p_R^2 - p_{wf}^2$ vs Q (gas rate) and extrapolating back to Q = 0 to obtain AOF = 12 MMscf/d (S = +17) or AOF = 29.9 MMscf/d (S = 0). Although the linear plot consists of only two points, the result appears to be quite good.

Comments
The high skin factor of +17 to +18 is due to formation damage rather than partial penetration effect as concluded by Blumer. This can be supported for two reasons. First, an inspection of the core permeability profile from Patricia-1 shows the top part of the Gurnard formation (which was open to test) is of much better quality than the lower part. Therefore Lasmo's interpreted peremability of 51-56 md is most probably valid. Secondly, the AOF of 29.9 MMscf/d for S = 0 is very similar to the AOF determined from the Patricia-1 DST #3A which yields AOF = 32.8 MMscf/d for S ≈ 1.0.

The important conclusion here is that the shale break in the middle of the Gurnard formation is a no-flow barrier.

2.3 Patricia-1 DST #1 (744 – 747 mRT)
Latrobe coarse clastics – Downhole valve was not closed. Data invalid.

2.4 Patricia-1 DST #2 (719 – 728 mRT)
Gurnard Formation - Isochronal test: Flow test followed by buildup, repeated two times with different rates (8.3, 5.1 and 6.1 MMscf/d).

Blumer Associates
Blumer did not interpret this test, but included it with test #3/3A.

Lasmo
The objective was to determine the productivity of this interval, which appeared to be of poor quality on logs, and later shown to have very low permeability from core measurement.

The formation capacity (kh) determined for this interval of 2308 md-ft was quite close to the kh for the whole of the Gurnard formation (see Test #3A below). Hence it was concluded that this interval was in communication with the sands above and below. This was also confirmed by poor cement bond across the interval.

All the flow and buildup periods were analyzed. They yield similar kh values in the range 2262 – 2333 md-ft, average 2308 md-ft, and skin factors between +13 and +16 from the buildups.

The AOF determined for this interval alone was 9.3 MMscf/d, but this value should be treated with caution due to communication with sands above and below.

2.5 Patricia-1 DST #3 (703 – 738 mRT)

Gurnard Formation – five separate flow periods, each followed by a buildup.

Results

The data were of very good quality, and both Blumer and Lasmo obtained similar results, except the Non-Darcy flow coefficient, which are compared below:

	Blumer Assoc	Lasmo
kh, md-ft	2507 -2576	2689 – 2720
h, ft	115	109
k, md	~ 22	~ 25
Skin factor	-1.5 to +3.3	+1.5
Non-Darcy Coeff. (F)	0.04 to 0.08	0.028
AOF, MMscf/d	Not calculated	31.9

Severe downhole restriction to flow efficiency was evident from low WHP's.

2.6 Patricia-1 DST #3A (703 – 738 mRT)

DST #3 was repeated with 5-1/2" drill pipe and simplifed test string. Both Blumer Associates and Lasmo obtained similar results:

	Blumer Assoc	Lasmo
k, md	21.2	20.9
Skin factor	-1.5	+1.1 to +1.3
Non-Darcy Coeff . (F)	0.03	0.028
AOF, MMscf/d	33.2	32.8
Radius of Investigation	N/A	108 ft

General Comments

The results of DST #3A supersede those of all the previous tests. The permeability from the DST is much lower than the bulk of core measurements. This could be related to the friable and unconsolidated nature of the cores.

From the drawdown and buildup pressures, a gas PI of 41.4 scf/psi^2 was obtained. The measured PI is considerably higher than the theoretical PI of 28 scf/psi^2 calculated with the steady state equation, assuming radial flow.

APPENDIX G TUBING SIZE SELECTION

Tubing Size - General

The optimum tubing size selection was chosen for Patricia and Baleen to maximise the ultimate recovery (UR).

In general small size tubing productivity is constrained during early part of the field life. In the presence of produced water the smaller size tubing can lead to increased ultimate recovery due to the requirement of a lower minimum gas rate to lift water.

Tubing Size – Patricia-Baleen

It is expected that the Gurnard Formation in both the Baleen and Patricia accumulations will have weak to no aquifer support. However, the Patricia well has a higher chance of water production based on the geometry of its structure with the potential of water influx from the SW region of the structure.

Simulation Results

Several simulation cases were run to optimise the tubing size. For a plant capacity of 50MMscf/d, two cases are presented.
Case 1: 5 ½" OD tubing (4.892" ID) run in both the Baleen and Patricia wells
Case 2: 5 ½" OD tubing (4.892" ID) run in the Baleen well with 3 ½" OD tubing (2.992" ID) in the Patricia well
Case 3: 3 ½" OD tubing (2.992" ID) run in both the Baleen and Patricia wells

Assumptions

In all cases, the reservoir section is completed with a 4.89" ID ESS.

Case 1 (Figure G1)
A plateau rate of period of 50MMscf/d is achieved for a period of six months. However the Patricia well waters out after two years production. The ultimate recovery of the field in Case 1 is 54 Bscf.

Case 2 (FigureG2)
A plateau rate of period of 50MMscf/d is achieved for a period of three months. The Patricia well waters out after in excess of seven years production. The ultimate recovery of the field in Case 2 is 59 Bscf.

Case 3 (Figure G3)
A maximum rate of 46 MMscf/d is achieved and assumed plant capacity of 50 MMscf/d is not utilised. The ultimate recovery of the field in Case 3 is 55 Bscf.

On an ultimate recovery basis, simulation results demonstrate that a 5 ½" OD tubing (4.892" ID) in the Baleen well and a 3 ½" OD tubing (2.992" ID) in the Patricia well gives an incremental volume of 5 Bscf over a 5 ½" OD tubing (4.892" ID) in both wells. Hence, a 5 ½"

OD tubing (4.892” ID) in the Baleen well and a 3 ½” OD tubing (2.992” ID) in the Patricia well is preferred.

The incremental ultimate recovery volume between Case 2 and Case 1 is attributed to the Patricia well. In Case 2 the Patricia well has an ultimate recovery of 18 Bscf versus 12 Bscf in Case 1 (Figure G3). The total field reserves of around 59 Bscf (Figure G1) compare with 54 Bscf for the case where both wells are completed with a 5 ½” OD tubing (4.892” ID) tubing.

Figure G1 Field Rate and Cumulative Production vs Time (Case 1 & Case 2)

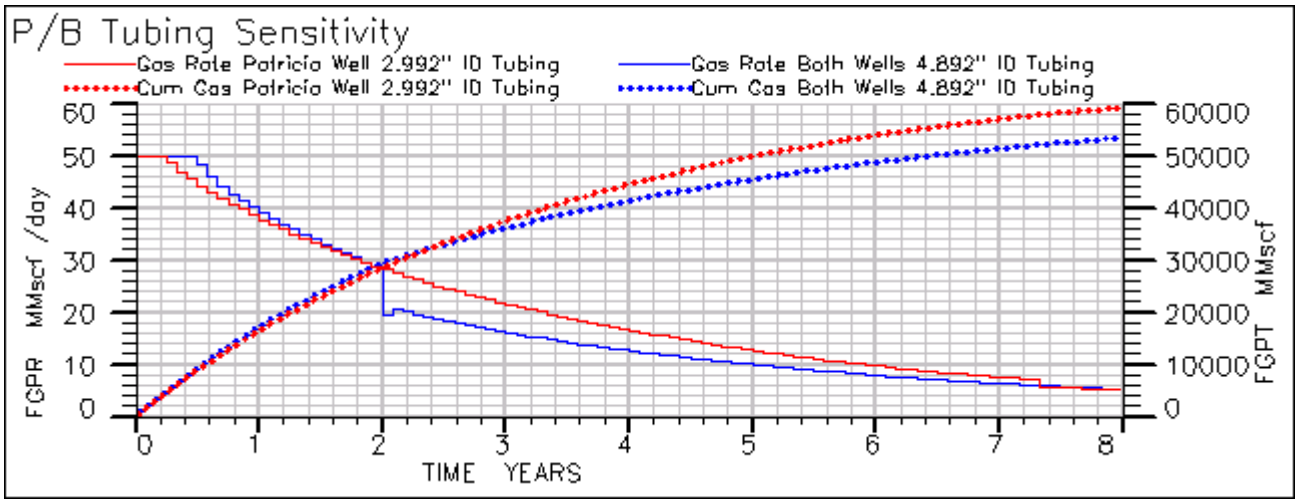


Figure G2 Patricia Well Performance – Water/Gas Rate and Cumulative Gas Production vs Time (Cases 1 & 2)

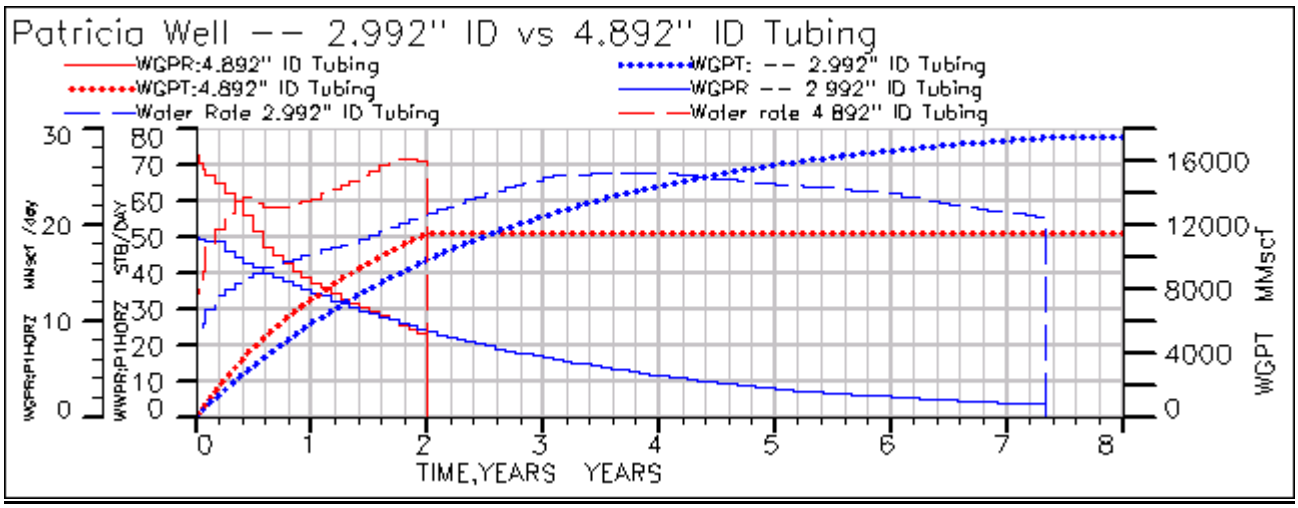
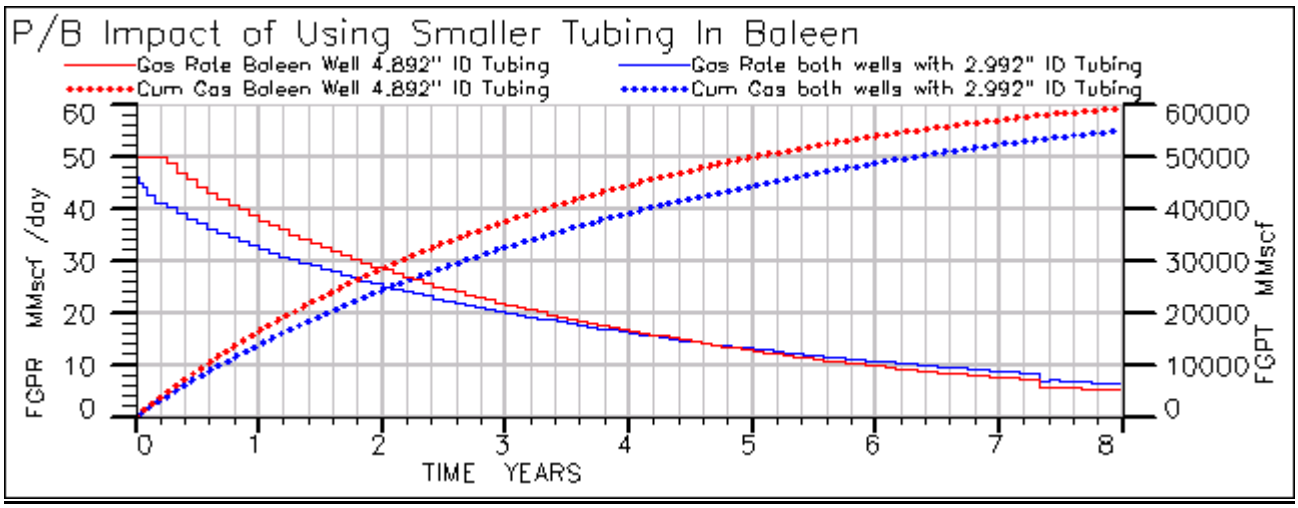


Figure G3 Case 3 – Patricia Baleen Combined Gas Rate and Cumulative Production vs Time (Patricia Well with 2.992" ID Tubing in both cases)



Conclusions

1. A 2.992" ID tubing for the Patricia well would result in an incremental gas recovery of 5 Bscf.
2. A 4.892" ID tubing for the Baleen well would result in better offtake rates and reserves over the eight-year field life. Unlike the Patricia well, the Baleen well is not expected to be constrained by water production.

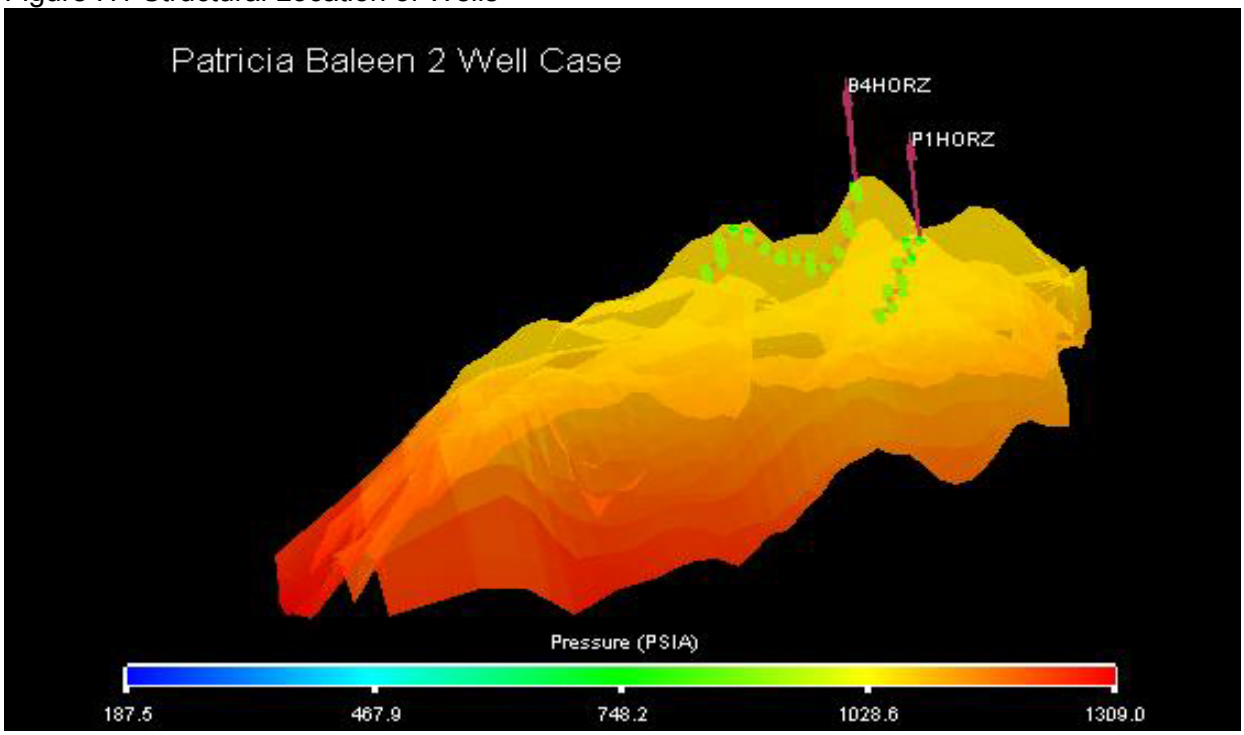
APPENDIX H PATRICIA-BALEEN: SENSITIVITIES ON THE NUMBER AND TYPE OF WELLS

Several cases were investigated varying the location, number and type (vertical, highly deviated and horizontal) of wells to optimise gas recovery.

The optimum development of two horizontal wells is compared with a development with a three horizontal well below.

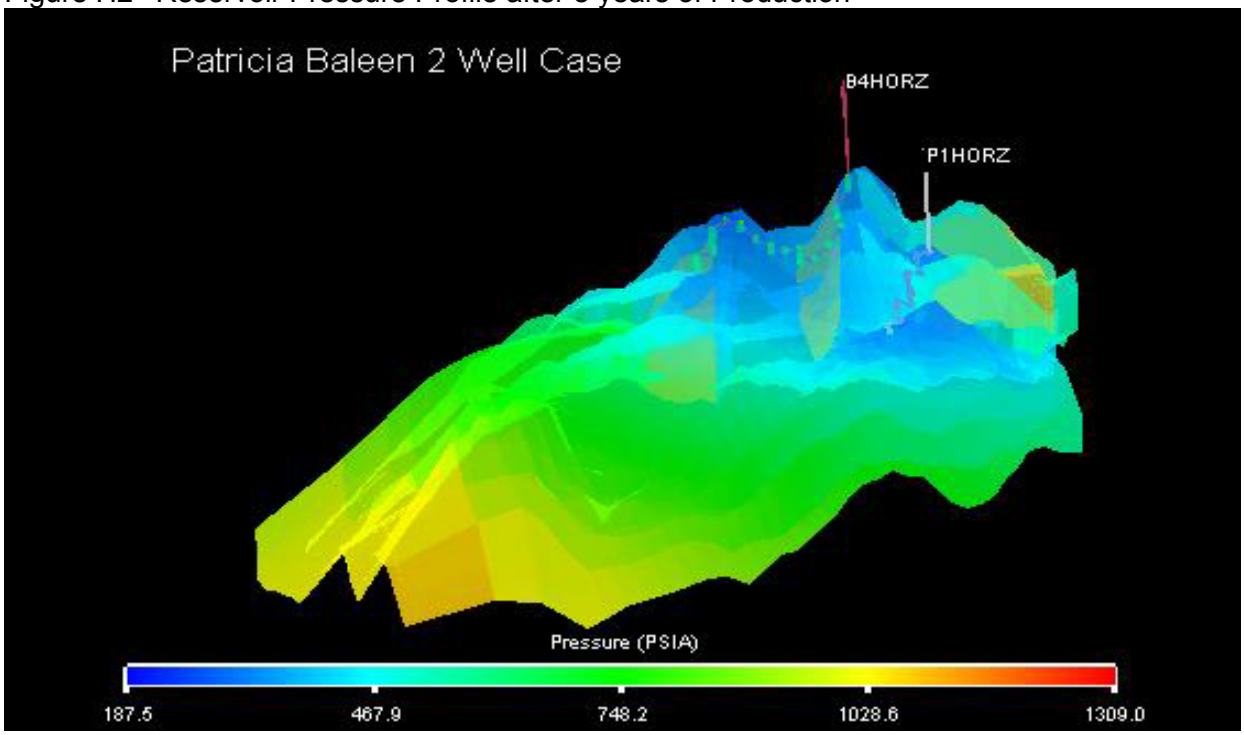
Two Horizontal Well Case
This case was run to ascertain how efficiently a single longer deviated well on the Baleen structure would drain the gas reserves. A 1700m well, as shown below, was imported into the simulation model and completed with a 4.892" tubing. The Patricia well was assumed to be completed with a 2.992" ID tubing and both wells were assumed to be cased with 4.892" ID ESS.

Figure H1 Structural Location of Wells



The reservoir pressure profile reached after eight years of production shows that the reservoir is efficiently drained with two wells (Figure H2).

Figure H2 Reservoir Pressure Profile after 8 years of Production



The Baleen 1700m well is capable of draining the structure. It effectively emulates two wells producing via one conduit. A significant advantage of the single long well is that it can continue to produce longer as it reaches MRTLL at a later stage of depletion.

Three Horizontal Well case

A three-deviated well case (two wells in the Baleen structure and one in Patricia – Figures H3 and H4) was run to ascertain potential improvement in reserves compared to the two well case. Since the two well case effectively delineated similar segments of the reservoir little difference in reserves was observed.

Figure H3 Structural Location of Wells

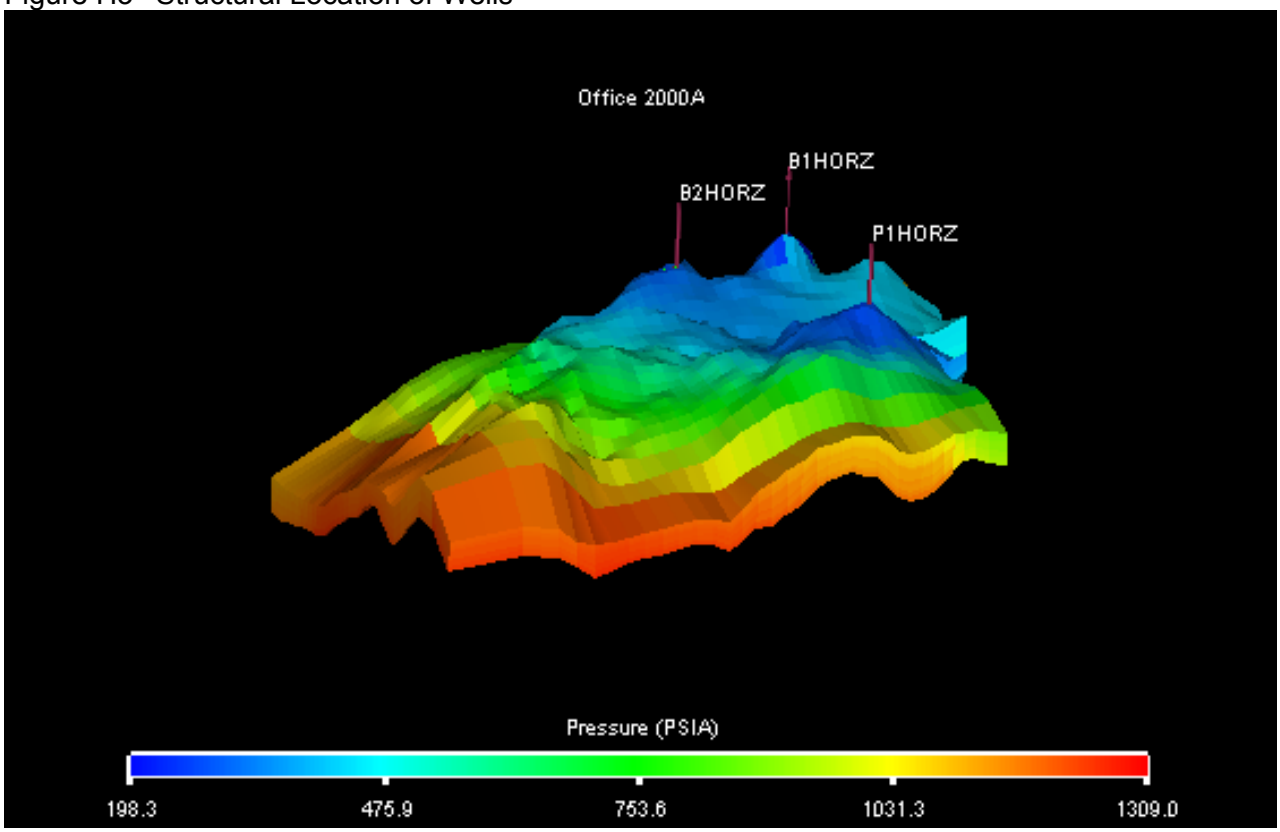


Figure H4 Areal Location of Wells

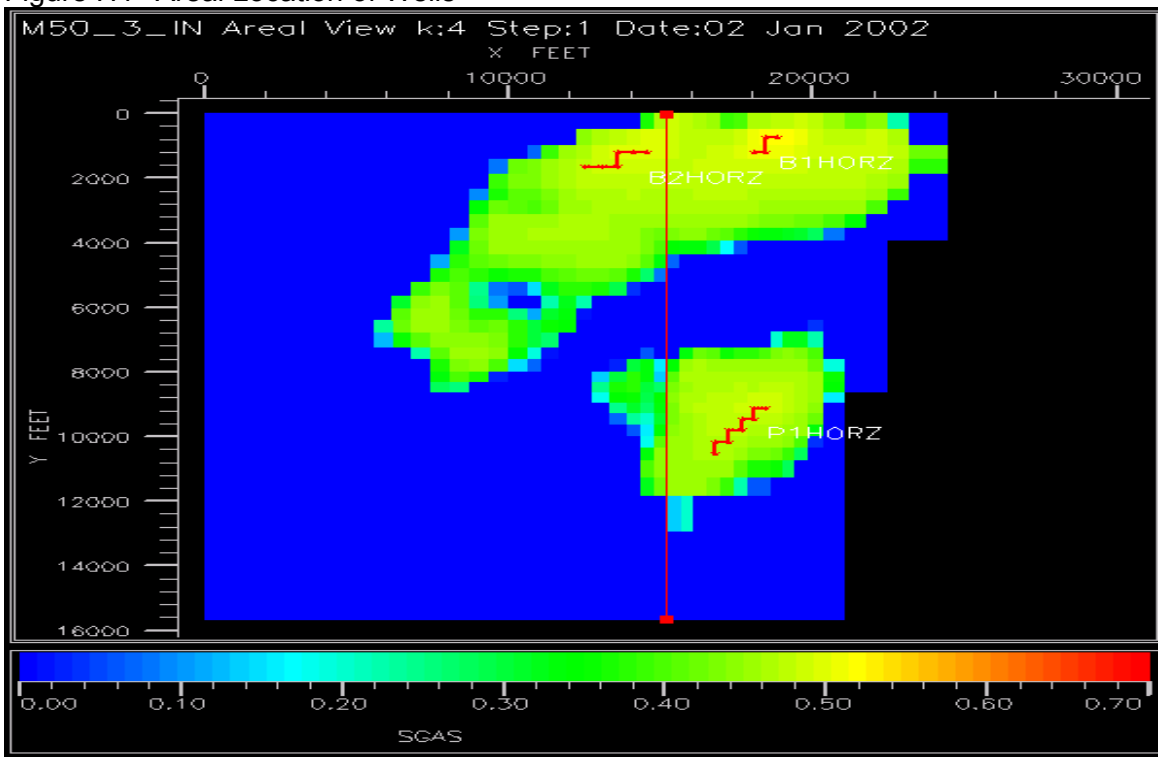
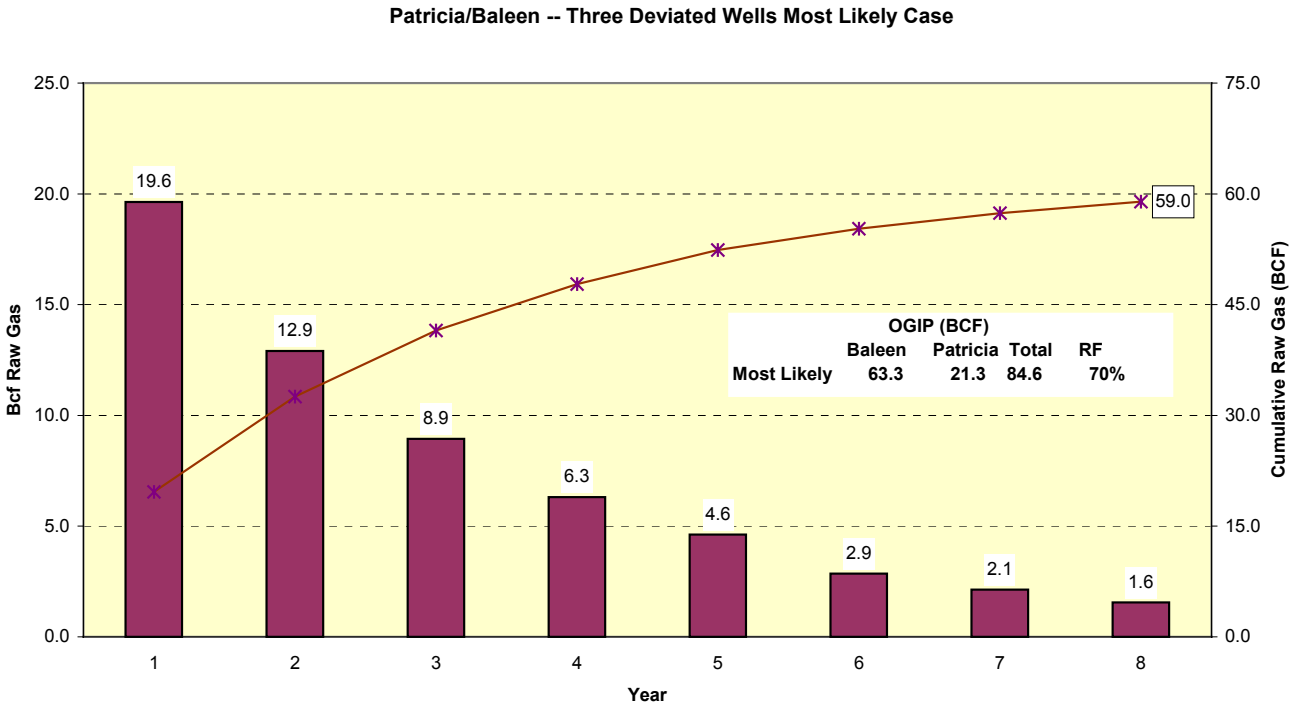


Figure H5 Field Production for Three Deviated Well case



Conclusion

The Patricia Baleen reserves will be effectively drained with two horizontal wells; one in the Baleen structure and the other in Patricia. Additional wells will be drilled if there is sufficient evidence that economic reserves would remain undrained.

APPENDIX I

HEALTH, SAFETY AND ENVIRONMENT POLICY

OMV Australia Pty Limited is a wholly owned subsidiary of OMV AG, Austria, an integrated oil and gas group. As an operator or partner, OMV Australia is involved in exploration, production and development projects.

OMV Australia is committed to providing and maintaining as far as practicable, a workplace that is without risks to health, safety and the environment. To meet this goal it is our policy to actively prevent injury and pollution, to conserve resources and to manage risks in accordance with leading industry practices and relevant regulations.

OMV Australia is committed to the continuous improvement of our health, safety and environmental performance.

We undertake to:

- Comply with all applicable laws, regulations and standards and actively participate in the promotion of health and safety and the protection of the environment throughout our operations.
- Identify, evaluate and manage major risks and impacts of our operations.
- Continuously increase awareness of our environmental and occupational health and safety responsibilities among our workforce; and make available training to enable them to work in a safe and environmentally sound manner.
- Provide systems to ensure that all incidents including property damage, near misses, concerns and complaints are reported, adequately investigated and steps taken to prevent recurrence.
- Conduct regular monitoring, periodic reviews and audits to ensure that this policy and management systems are being correctly implemented, maintained, improved and updated.
- Ensure that health, safety and environmental objectives and targets are established and given the same regard as our operational goals and objectives.
- Develop communication channels that ensure that this policy and its objectives are understood by all employees, contractors, visitors and customers and to actively seek their input and feedback.
- Consult with all stakeholders, both internal and external on health, safety and environmental matters and where appropriate make the policy available to the public.

This policy applies to all OMV Australia controlled activities.

W. Zimmer
Managing Director
October 2000