The Contemporary Stress Field of the Nappamerri Trough and Its Implications for Tight Gas Resources

Richard R. Hillis
Jeremy J. Meyer
Marian E. Magee

(October 1997)

Department of Geology and Geophysics
University of Adelaide, SA 5005, AUSTRALIA

Ph: 08 8303 5376 (Sec)
08 8303 5377 (Dir)
Fax: 08 8303 4347
E-mail: rhillis@geology.adelaide.edu.au

Executive Summary

The maximum horizontal stress (σ_{hmax}) is oriented approximately east-west in the Nappamerri Trough area. The overburden stress (σ_v) gradient is approximately 1.0 psi/ft in the Cooper Basin sequence of the Trough. The minimum horizontal stress (σ_{hmin}) gradient in the Eromanga Basin sequence surrounding the Trough is approximately 0.8 psi/ft. At depths of 6 000-9 000 ft within the Trough formation integrity pressures lie on the 0.8 psi/ft trend, and σ_{hmin} magnitude is underconstrained, but probably somewhat in excess of 0.8 psi/ft. Overpressures, approaching 0.8 psi/ft, occur in the Trough at depths in excess of 9 000 ft. The magnitude of σ_{hmax} is poorly constrained, but the occurrence of tensile fractures apparent on resistivity image logs suggests that it is at least as great as σ_v. In overpressured zones σ_{hmin} is likely to be close to or may even exceed σ_v. Hence the likely range of the stress regimes in the Nappamerri Trough is between $\sigma_{hmin} < \sigma_v \approx \sigma_{hmax}$ (boundary of extensional and strike-slip in normally pressured areas surrounding the Trough) and $\sigma_{hmin} \approx \sigma_v < \sigma_{hmax}$ (the boundary of strike-slip and compression in overpressured areas).

Although detailed application of contemporary stress field data to fracture stimulation and wellbore stability requires data beyond that available for this study (such as hydraulic fracture-type and strength testing), some important conclusions can be drawn from the available data.

Given the low permeability of tight gas sands in the Nappamerri Trough, naturally fractured zones represent important potential 'sweet spots' of improved permeability. Fractured gas reservoirs at Lycosa-1 and Moolalla-1 (southwest of the Nappamerri Trough), and natural fractures in the lower Patchawarra - basement of Moomba-73, highlight the potential for naturally fractured plays. Any steeply-dipping, east-west striking, pre-existing fractures in the Nappamerri Trough, are orthogonal to σ_{hmin} and thus optimally oriented to be open and productive. Hence horizontal wells in the Nappamerri Trough designed to maximise intersection with open natural fractures should be deviated in a northerly or southerly azimuth.

Overpressures may be conducive to the formation of a regional, systematic fracture set oriented orthogonal to σ_{hmin}, similar to that which plays a major role in enhancing permeability in the Mesaverde tight gas reservoirs of Colorado. Wells deviated to the north or south are best oriented to intersect such a potential regional fracture set.

Fracture stimulation may produce commercial flows from tight gas sands. However, drilling-induced tensile fractures interpreted on FMS images are steeply dipping and oblique to vertical wellbores, occurring in en echelon sets, each fracture intersecting the wellbore over a distance only of the order of 1 ft, and often terminate against, or are offset by conductive horizontal

layers interpreted to be coal laminae. Hence fracture stimulation is likely to form tortuous fracture networks resulting in high treatment pressures, poor proppant transport and screenout. In order to minimise the propensity for complex fracture networks, homogeneous stimulation intervals should be selected. Furthermore, slightly inclined wellbores, parallel to the dip of the fractures, or east-west trending horizontal wellbores should result in single, axial fractures. Image logs should be analysed prior to fracturing to investigate these aspects of the stimulation interval. Alternatively multiple fracture development may be inhibited by fracturing from a pseudo-point source.

Overpressures and associated high horizontal stresses are likely to exacerbate the difficulty of fracture stimulation. Horizontal hydraulic fractures may enhance production less than vertical fractures, and are likely to be associated with multiple fracture generation. Fracture twisting and second-phase fracture generation are likely to lead to tortuous fracture networks. Depletion of overpressured reservoirs prior to stimulation should ameliorate problems associated with overpressured reservoirs.

There appears to be no 'safe' mud weight at which both breakout and tensile fracture are successfully inhibited in vertical wells in the Nappamerri Trough. This is typical of areas with a high horizontal stress anisotropy. Mud weight selection should be based on an assessment of the relative disadvantages of tensile fractures (mud losses) and breakout (wellbore instability) to the objectives of the well. The case for improved wellbore stability through increased mud weight must be balanced against the associated potential for increased formation damage to the low porosity/low permeability reservoirs.

In the strike-slip stress regime horizontal wellbores of any azimuth should generally be more stable than vertical wellbores. In normally pressured areas surrounding the Trough ($\sigma_{hmin} < \sigma_v \approx \sigma_{hmax}$) north-south oriented horizontal wellbores would be the least prone to breakout. In overpressured areas ($\sigma_{hmin} \approx \sigma_v < \sigma_{hmax}$) east-west oriented horizontal wellbores would be the least prone to breakout. As the stress field changes from $\sigma_{hmax} \approx \sigma_v$ to $\sigma_{hmin} \approx \sigma_v$, the most stable drilling direction changes from σ_{hmin} to σ_{hmax}.

Contents

1. Introduction

The Nappamerri Trough is a depocentre within the Permo-Triassic Cooper Basin of South Australia/Queensland. Permian sandstone reservoirs represent a vast gas resource in the Trough. However, commercial flows have not been obtained from the relatively low porosity (generally < 10%), low permeability (< 1 md) sandstones buried at around 8 000' - 12 000' within the Nappamerri Trough.

This report is one of a series commissioned by the Department of Mines and Energy, South Australia on the tight gas resources of the Nappamerri Trough under the auspices of the Tight Gas Resources Project (TIGRES). It analyses the contemporary stress field of the Nappamerri Trough and surrounding areas, and addresses the implications of the contemporary stress field for tight gas exploration and development, with specific reference to:

- open natural fracture orientations and naturally fractured plays;
- fracture stimulation, and;
- wellbore stability.

2. Breakouts, Tensile Fractures and Horizontal Stress Orientation

2.1 The Formation of Breakouts and Tensile Fractures

Borehole breakouts and tensile fractures represent two different modes of stress-induced failure of the wellbore wall, both of which can be used to determine the orientation of the contemporary stress field, given an understanding of the stresses acting around a wellbore.

The presence of an open wellbore disturbs the far-field stresses within the subsurface. The circumferential or hoop stresses ($\sigma_{\theta\theta}$) acting at the wellbore wall are described by:

$$\sigma_{\theta\theta} = \sigma_{hmax} + \sigma_{hmin} - 2(\sigma_{hmax} - \sigma_{hmin})\cos 2\theta - P_w - P_0, \qquad (2.1)$$

where σ_{hmax} and σ_{hmin} are the total maximum and minimum far-field horizontal stresses respectively, θ is the angle at the wellbore wall measured from the azimuth of σ_{hmax}, P_w is the mud pressure in the wellbore, and P_0 the pore pressure of the formation (Moos & Zoback, 1990).

From Equation 2.1 it is clear that the circumferential stresses are maximised at 90° and 270° to the azimuth of σ_{hmax} (ie. at the azimuth of σ_{hmin}), where they are given by:

$$\sigma_{\theta\theta max} = 3\sigma_{hmax} - \sigma_{hmin} - P_w - P_0. \qquad (2.2)$$

Where the circumferential stress exceeds the compressive strength of the rocks forming the wellbore wall, compressional shear failure may occur (Figure 2.1). Failure of intersecting conjugate shear failure planes leads to pieces of rock spalling, or breaking off the wellbore wall. An elongation of the wellbore cross-section in the direction of σ_{hmin}, which is known as borehole breakout, may result (Figure 2.1).

From Equation 2.1 it is also clear that the circumferential stresses are minimised at 0° and 180° to the azimuth of σ_{hmax} (ie. at the azimuth of σ_{hmax}), where:

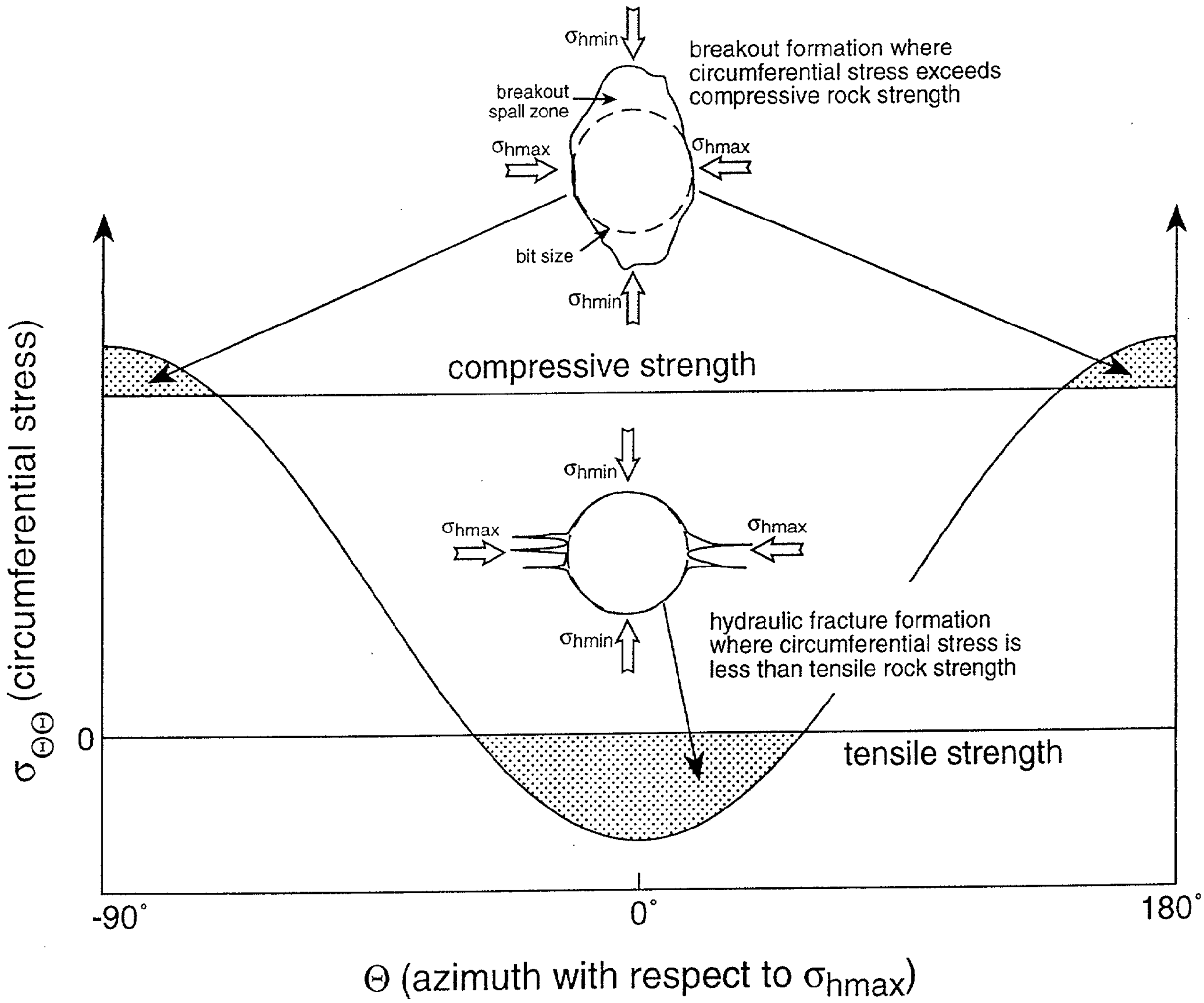
$$\sigma_{\theta\theta min} = 3\sigma_{hmin} - \sigma_{hmax} - P_w - P_0. \qquad (2.3)$$

Tensile fractures form where the circumferential stress is less than the tensile strength of the rocks forming the wellbore wall (tensile stresses are defined here to be negative) (Figure 2.1). Tensile fractures are thus oriented at right angles to breakouts. Considering the effect of P_w in the above equations, breakouts can form when the mud weight is insufficiently high to support the wellbore wall and tensile fractures when the mud weight is excessively high.

2.2 Breakout and Fracture Identification on Dipmeter and Image Log Data

Breakouts can be recognised on four-arm dipmeter logs such as that of Schlumberger's HDT (High Resolution Dipmeter Tool). Four-arm dipmeter tools record their orientation and inclination while four caliper arms, hydraulically pressed against the wellbore wall, measure the width of the wellbore in two orthogonal directions. As the four-arm dipmeter tool is raised up the wellbore, cable torque causes it to rotate about a vertical axes until ellipticity of the wellbore cross-section causes one pair of caliper arms to lock in the long axis of the breakout. These characteristics of tool behaviour lead to the rules cited in Table 2.1 for breakout recognition. The principal purpose of these rules is to discriminate between stress-induced elongation of the wellbore cross-section (ie. true breakout) and other elongation induced by drilling itself, such as mudcakes, washouts, and key seats (Plumb & Hickman, 1985; Dart & Zoback, 1989; Prensky, 1992).

Figure 2.1 The variation of circumferential stress acting at the wellbore wall with azimuth around the wellbore. Also shown are schematic cross-sections of wellbore shape associated with breakout and tensile, hydraulic fracturing.



Criterion	Description
1	Tool rotation stops in the breakout.
2	Tool rotates beneath the breakout.
3	Smaller caliper width is within 5% of bit size.
4	Difference between caliper widths is greater than 6 mm.
5	Length of the breakout is greater than 1.5 m.
6	Direction of the breakout must not coincide with the high side of the well bore if deviation is greater than 1°.

Table 2.1 Criteria used in the discrimination of breakouts from drilling-induced deformations of the wellbore.

Schlumberger's Formation MicroScanner (FMS) tool evolved from the HDT. The version of the FMS from which data from the Nappamerri Trough were analysed comprises sixteen resistivity sensors at the end of each of the four arms of the FMS which produce four 2.5 inch swaths of microresistivity readings. Each swath provides an electrical image of the wellbore wall. As in the HDT, the orientation and inclination of the tool is measured as are the widths of the wellbore across the two orthogonal pairs of arms.

The FMS tool provides the same caliper width and orientation data as the HDT, but the resistivity images greatly facilitate breakout identification and can also be used for fracture analysis which cannot be undertaken using HDT data. Breakouts appear on FMS resistivity images as relatively wide zones of low resistivity, where the wellbore wall has been subject to compressional shear failure. The wellbore cross-section is usually elongated, due to spalling of the wellbore wall, on the same caliper pair as the low resistivity zone is observed. Resistivity images of breakouts often have a characteristic 'blobby' appearance due to poor resolution caused by hole rugosity associated with spalling of the wellbore wall. Breakouts are generally axial to the wellbore, and thus vertical in the vertical wells of the Nappamerri Trough.

Open fractures intersecting the wellbore appear on the FMS images as high aspect ratio, angular, low resistivity features. If open, fractures are filled with mud or mud filtrate and therefore conductive relative to the surrounding rock. It can be difficult to differentiate between drilling-induced tensile fractures and pre-existing natural fractures on FMS images, although there are some key features which distinguish them. Drilling-induced tensile fractures are open and conductive, and are often recognised as steeply-dipping events consistently orthogonal to breakouts. Natural fractures may be conductive or resistive, but tend to display more variable orientation then drilling-induced tensile fractures.

2.3 Breakout and Horizontal Stress Orientation in the Nappamerri Trough

Of the wells within the Nappamerri Trough, HDT/FMS data were only available for Bulyeroo-1. For this reason, data from wells surrounding the Nappamerri Trough (seven with HDT data and four additional to Bulyeroo-1 with FMS data) were also analysed.

The results of breakout analysis are summarised in Table 2.2 and inferred σ_{hmax} directions are shown on the map of Figure 2.2. A quality rating, the same as that used by the World Stress Map (Zoback, 1992), has been determined for the mean breakout orientation in each well. In general, an A quality rating is for a well in which many breakouts are observed over a long depth interval with consistent orientation (ie. low standard deviation). Wells where the σ_{hmax} orientation is given a poor quality rating (D) have either very few breakouts, or breakouts with inconsistent orientation.

The inferred mean σ_{hmax} direction lies between 072°N and 105°N for all but two wells. Moorari-7 and Woolkina-1 in the northwest of the area exhibit an approximately northwest-southeast σ_{hmax} orientation. However, the σ_{hmax} orientation inferred from the breakouts in the other ten wells is consistent and oriented approximately east-west. Considering only the best quality data (A or B-rated), σ_{hmax} is inferred to be 090°N-100°N within the Nappamerri Trough. Care must be taken when inferring regional stress orientations from these measurements, because structures such as anticlines and faults can locally deflect the stresses from the regional trend. There are insufficient data to assess whether the northwest-southeast stress orientations

Well	Logging Tool	Depth Interval	Stratigraphic Interval	Lat	Lon	Breakouts N	Azi	SD	Q
Bulyeroo-1	FMS	8911'-9580'	Nappamerri Group-Roseneath Shale	27°50'22"	140°34'38"	14	179°	7°	A
Dullingari-13	HDT	4091'-5126'	Bulldog Shale-Namur Sandstone	28°06'22"	140°52'30"	5	162°	24°	C
Dullingari-24	HDT	4349'-8743'	Bulldog Shale-Dullingari Group (Basement)	28°06'40"	140°53'35"	5	177°	14°	C
Dullingari-27	HDT	2392'-5029'	Mackunda Formation-Murta Formation	28°06'54'	140°52'30"	20	008°	18°	B
Dullingari-33	HDT	4093'-5182'	Bulldog Shale-Namur Sandstone	28°04'59"	140°51'14"	3	171°	50°	D
Moomba-73	FMS	8150'-8747' & 9222'-9974'	Nappamerri Group-Big Lake Suite (Basement)	28°01'04"	140°15'21"	19	008°	6°	A
Moomba-74	FMS	8105'-8498'	Nappamerri Group-Daralingie Formation	28°02'23"	140°07'40"	10	014°	5°	A
Moomba-78	FMS	8202'-8743' & 9055'-9482' & 9646'-9777'	Nappamerri Group-Upper Patchawarra	28°04'27"	140°19'23"	21	011°	6°	A
Nappacoongee East-1	FMS	5725'-6425'	Hutton Sandstone-Basement	28°01'35"	140°46'52"	11	015°	7°	A
Moorari-7	HDT	5842'-9863'	Cadna-owie Formation-Merrimelia Formation	27°34'12"	140°08'10"	6	052°	11°	B
Wantana-1	HDT	7996'-9661'	Nappamerri Group-Kalladeina Formation (Basement)	27°37'59"	140°25'23"	8	010°	8°	B
Woolkina-1	HDT	5781'-8262'	Cadna-owie Formation-Nappamerri Group	27°35'24"	140°07'01"	1	062°	-	D

Table 2.2. Summary of results of breakout analysis. N is the number of breakouts, Azi is their mean directional azimuth, SD is standard deviation, Q is quality rating (confidence level) of the mean azimuth.

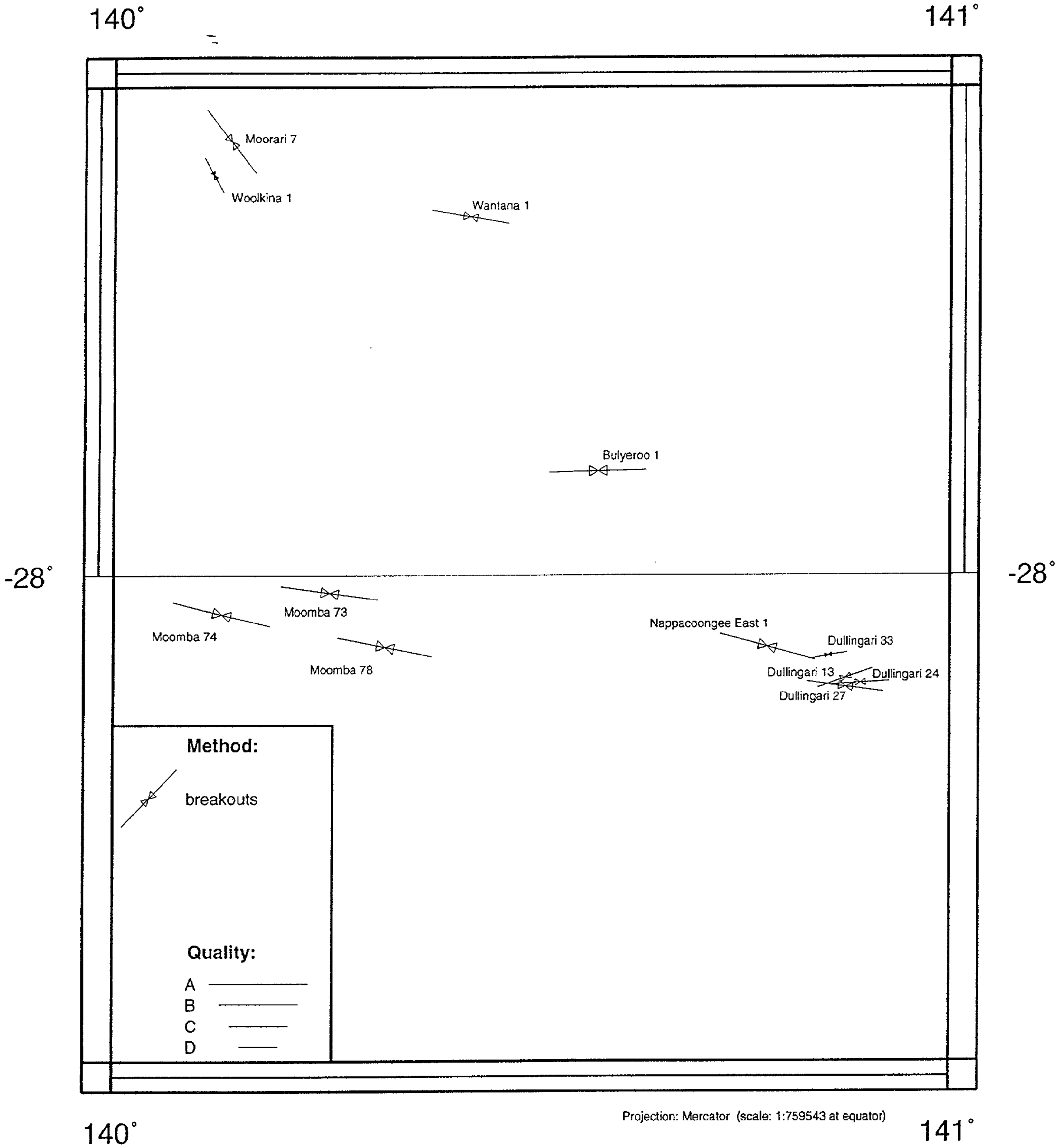


Figure 2.2 Maximum horizontal stress (σ_{hmax}) directions inferred from mean borehole breakout directions in wells in the Nappamerri Trough area. The quality ratings of the inferred σ_{hmax} directions ranges from A (many breakouts with a consistent orientation) to D (very few breakouts, or several breakouts with inconsistent orientation).

at Moorari-1 and Woolkina-1 reflect a local stress rotation, or are part of a more regional stress rotation which extends to the northwest of the study area.

2.4 Fractures and Horizontal Stress Orientation in the Nappamerri Trough

The results of fracture analysis are summarised in Table 2.3 and inferred σ_{hmax} directions are shown on the map of Figure 2.3. Of the five wells with FMS data, only Moomba-74 exhibited no fractures. The vast majority of logged fractures were steeply-dipping, conductive and consistently oriented orthogonal to breakouts. These are interpreted as drilling-induced tensile fractures. Given the consistency of the σ_{hmax} orientation inferred from tensile fractures with that based on breakouts, the east-west orientation is considered to be reliable.

In the lower Patchawarra and basement of Moomba-73, fractures occur which are of variable conductivity, not orthogonal to breakout (dominant strike northwest-southeast) and variable dip (30° to sub-vertical). These fractures are readily distinguished from the drilling-induced tensile fractures and are interpreted as natural fractures. In the lower Patchawarra of Moomba-73 there is a dominant northwest striking fracture set and a subsidiary northeast striking set (note the high standard deviation associated with the mean fracture azimuth over this interval, Table 2.3). Such orthogonal natural fracture sets are commonly observed in flat-lying sedimentary strata (eg. Lorenz et al., 1991). The basement of Moomba-73 shows only the northwest oriented fracture set (note the low standard deviation associated with the mean fracture azimuth over this interval, Table 2.3). These natural fractures in the lower Patchawarra and basement of Moomba-73 were not used to infer contemporary σ_{hmax} orientation, and are not represented in Figure 2.3, because they are not drilling-induced fractures.

Well	Logging Tool	Depth Interval	Stratigraphic Interval	Lat	Lon	Fractures N	Azi	SD	Q
Bulyeroo-1	FMS	8911'-9580'	Nappamerri Group-Rosencath Shale	27°50'22"	140°34'38"	32	097°	20°	B
Moomba-73 (all)	FMS	8150'-8747' & 9222'-9974'	Nappamerri Group-Big Lake Suite (Basement)	28°01'04"	140°15'21"				
Moomba-73	*FMS*	*8150'-8747 & 9222'-9711'*	*Nappamerri Group-upper Patchawarra*	*28°01'04"*	*140°15'21"*	*28*	*104°*	*16°*	*B*
Moomba-73	*FMS*	*9711'-9875'*	*lower Patchawarra*	*28°01'04"*	*140°15'21"*	*21*	*146°*	*43°*	*D*
Moomba-73	*FMS*	*9875-9974'*	*Big Lake Suite (Basement)*	*28°01'04"*	*140°15'21"*	*17*	*147°*	*19°*	*B*
Moomba-74	FMS	8105'-8498'	Nappamerri Group - Daralingie Formation	28°02'23"	140°07'40"	0	-	-	
Moomba-78	FMS	8202'-8743' & 9055'-9482' & 9646'-9777'	Nappamerri Group - upper Patchawarra	28°04'27"	140°19'23"	64	105°	16°	B
Nappacoongee East-1	FMS	5725'-6425'	Hutton Sandstone-Basement	28°01'35"	140°46'52"	136	102°	15°	B

Table 2.3. Summary of results of fracture analysis. N is the number of fractures, Azi is their mean directional azimuth, SD is standard deviation, Q is quality rating (confidence level) of the mean azimuth. In Moomba-73 fractures in the Toolachee-upper Patchawarra are interpreted as drilling-induced fractures, whereas those in the lower Patchawarra and basement are interpreted as natural fractures (see text for further discussion).

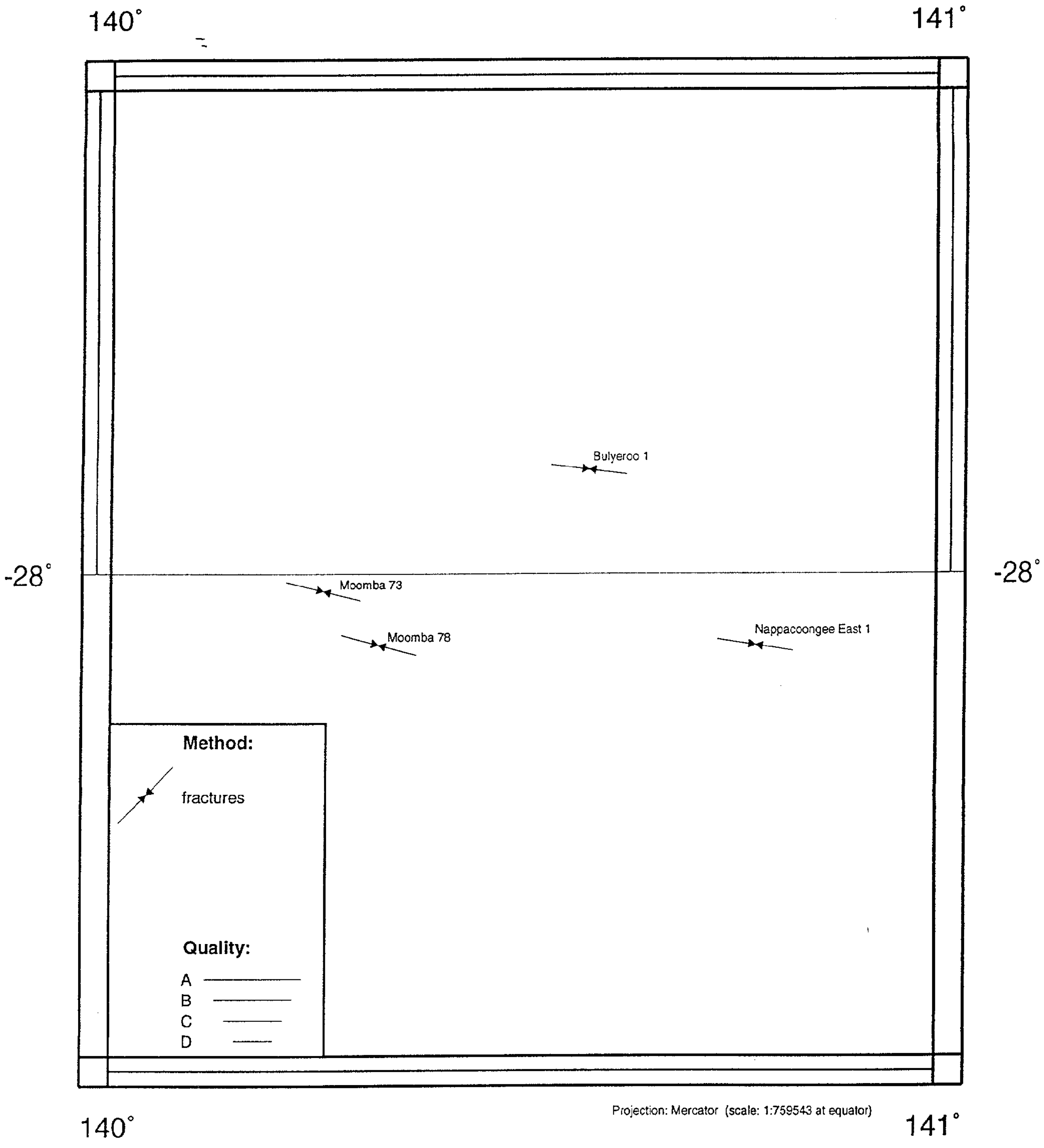


Figure 2.3 Maximum horizontal stress (σ_{hmax}) directions inferred from mean tensile fracture directions in wells in the Nappamerri Trough area. The quality rating system for the inferred σ_{hmax} directions ranges from A (many fractures with a consistent orientation) to D (very few fractures, or several fractures with inconsistent orientation). All four directions plotted are of B quality.

2.5 Breakouts and Wellbore Instability in the Nappamerri Trough

Borehole breakout is the main cause of wellbore instability in the Nappamerri Trough area. This section discusses controls on the occurrence of borehole breakout in the area. The implications for deviated and horizontal wellbore stability are discussed in Section 6.3.

Observations from FMS log interpretation indicate that there is a broad lithological control on breakouts, and thus hole quality in the Nappamerri Trough area. Hole quality tends to be worst in the coals, poor in the sandstones and best in the shales. Hence, hole quality tends to be poorest in the Toolachee Formation, poor in the coals and sandstones of the Daralingie, Epsilon and Patchawarra Formations, and good in the Roseneath and Murteree Shales.

The greater propensity for breakout in sandstones than shales contrasts with other basins such as the Otway Basin where shales are more prone to breakout than sandstones (Hillis et al., 1995). The tendency for poor hole quality in the sandstones often makes log interpretation problematic in the reservoir intervals. Consideration of Equation 2.2 indicates that the tendency for coals and sandstones to breakout more than shales implies that either the stress concentration, which controls the maximum circumferential stress acting at the wellbore wall ($3\sigma_{hmax} - \sigma_{hmin}$, Equation 2.2), is greater within these lithologies than in the shales, and/or the coals and sandstones are weaker under compression.

Of the wells for which FMS logs were analysed (Bulyeroo-1, Moomba-73, 74 and 78, and Nappacoongee East-1), Bulyeroo-1 is the only well within the Nappamerri Trough, and it exhibits the poorest hole condition. This is despite Bulyeroo-1 having been drilled with a higher mud weight (up to 14.8 lbs/gal) than the wells surrounding the Trough (approximately 10 lbs/gal). As discussed in Section 2.1, higher mud weights act to support the wellbore wall and suppress breakout. Thus if we assume other drilling and rock strength parameters are constant, it may be inferred that the parameter which controls the maximum stress acting around the wellbore ($3\sigma_{hmax} - \sigma_{hmin}$), is higher than in the region surrounding the Trough.

2.6 The Morphology of Drilling-Induced Tensile Fractures

Drilling-induced tensile fractures form due to excess pressure within the wellbore, and are directly analogous to those formed in fracture stimulation. However, drilling-induced fractures in the Nappamerri Trough are not, as is commonly assumed in fracture stimulation, simple, planar, two-winged, penny-shaped fractures. This chapter discusses the morphology of drilling-induced fractures. Section 6.2 addresses the largely detrimental implications of their complex morphology for fracture stimulation.

As witnessed by FMS images, drilling-induced tensile fractures:

- consistently strike east-west (Figure 2.4);
- are steeply dipping but only rarely vertical (typically 70-90°N);
- are oblique to the wellbore;
- occur in en echelon sets with each fracture intersecting the wellbore over a distance only of the order of 1 ft (Figure 2.4);
- often terminate against, or are offset by horizontal conductive layers (the conductivity of which is often enhanced in the vicinity of the fractures, Figure 2.4), and;
- locally create a saw tooth pattern (due to their intersection with the conductive horizontal layers at which they are often offset, Figure 2.4).

The conductive horizontal layers at which steeply dipping fracture segments terminate occur at mud weights only slightly in excess of hydrostatic. The conductive horizontal layers are thus not horizontal hydraulic fractures which could only form at mud weights in excess of the overburden stress of approximately 1 psi/ft (Chapter 3). The log characteristics of thicker coal units and analysis of cores, which show many friable coal laminations, suggest that these thin horizontal layers are coal-rich laminations. It is inferred that steeply dipping hydraulic fractures propagate through the sandstones or shales, but their growth is arrested, at least temporarily, by the friable coal laminations into which drilling mud leaks off. The phenomenon is considered to be similar to that described by Warpinski and Teufel (1987) in their discussion of the effect of geological discontinuities on hydraulic fracture propagation.

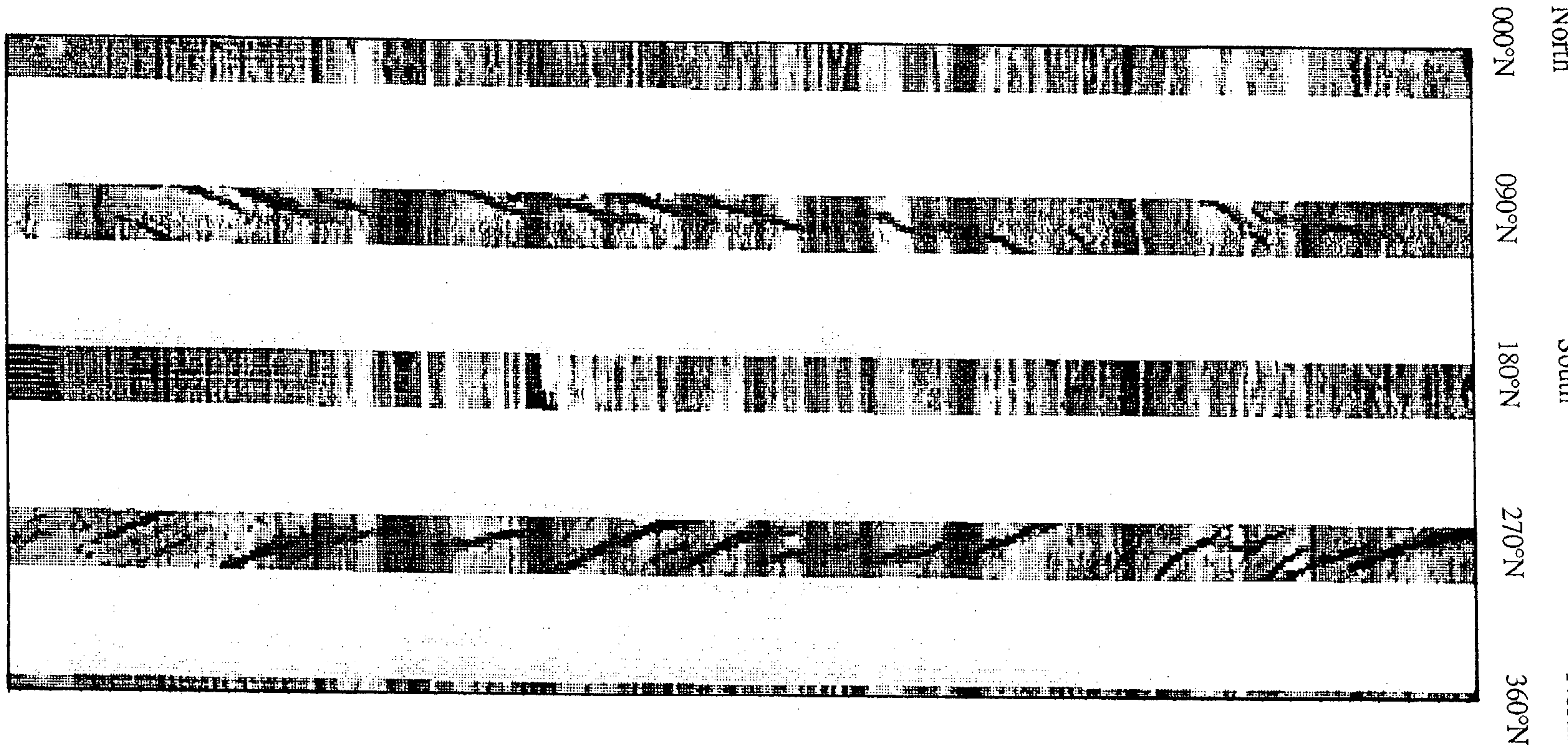


Figure 2.4 Resistivity image from the Nappamerri Trough area showing the complexity of drilling-induced tensile fractures. The interval shown is 10 ft thick. Dark shades correspond to low resistivity and light shades high resistivity. The sub-horizontal variation in resistivity reflects lithological changes associated with bedding. The steeply-dipping features of low resistivity are drilling-induced tensile fractures. See text for discussion of the nature of the fractures.

It is also significant to fracture stimulation procedures that the fractures are not vertical and occur oblique to the wellbore in en echelon sets. This may be because the minimum principal stress, to which the fractures are orthogonal, is slightly inclined to the horizontal. Alternatively, there may be a pre-existing anisotropy (eg. near vertical joint set) which the fractures are utilising. The interaction of such a pre-existing joint set with the interpreted coal laminations is consistent with the observed saw-tooth fracture pattern. It is postulated that fractures open a pre-existing steeply dipping anisotropy where it has an east-west azimuth at the wellbore wall. However, as fractures propagate along the pre-existing anisotropy they become misaligned with respect to their geomechanically-preferred east-west azimuth at the wellbore wall, and where fracture growth is arrested by the coal laminations, fractures re-open at an east-west azimuth.

3. Vertical Stress Magnitude in the Nappamerri Trough

3.1 Vertical Stress Determination

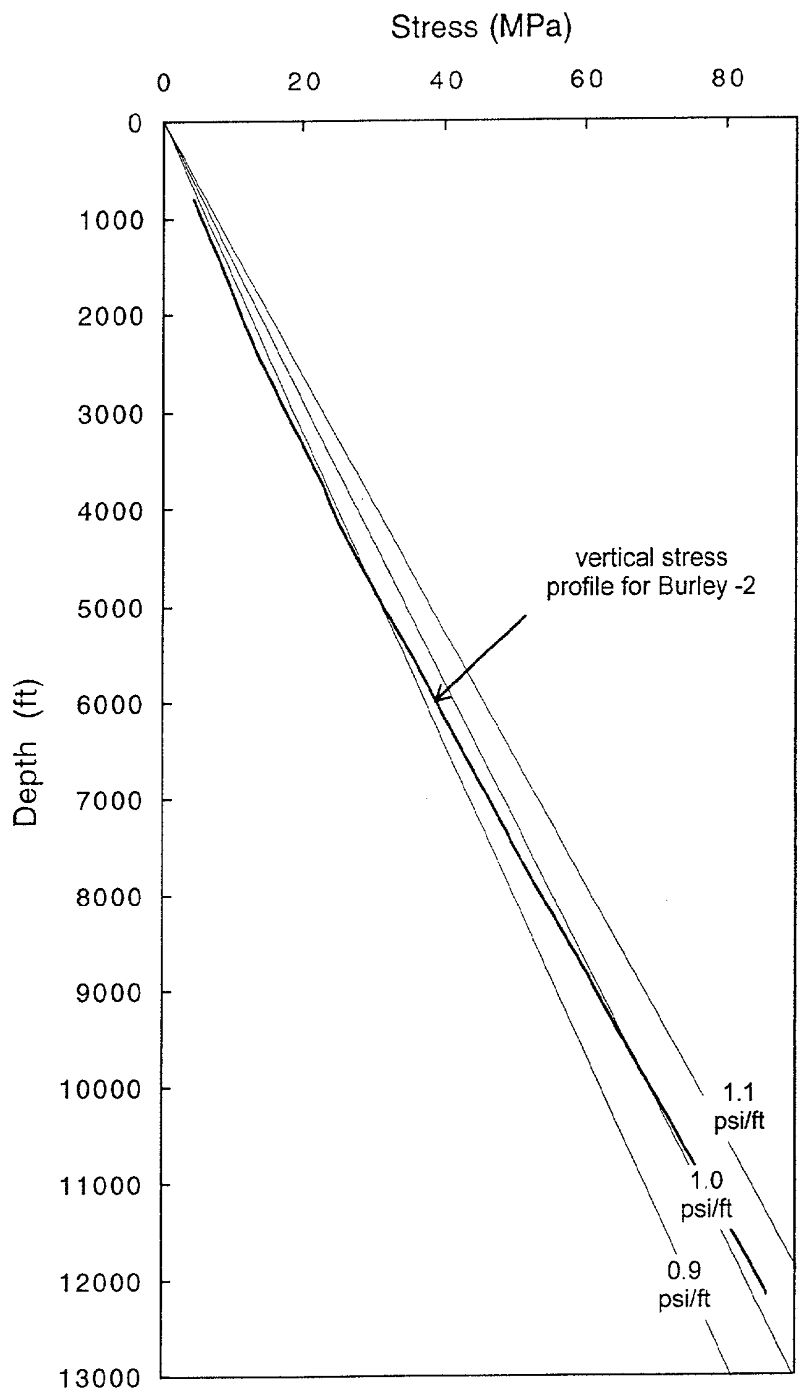
The vertical or overburden stress (σ_V) at a specified depth can be equated with the pressure exerted by the weight of the overlying rocks and is expressed as:

$$\sigma_V = \int_0^z \rho(z) g \, dz, \tag{3.1}$$

where $\rho(z)$ is the density of the overlying rock column at depth z, and g is the acceleration due to gravity. Hence it is necessary to know the density of the rock column in order to determine the magnitude of the vertical stress. Since Dickinson's (1953) classic paper on Gulf Coast pressure, it has been commonplace to adopt a value of 2.3 gcm^{-3} for the mean density of sedimentary rocks. The popularity of this value is partly due to the fact that the resulting overburden pressure gradient is 1.0 psi/ft (22.6 MPa/km). However, where density data are available for the rock column, this value should not be assumed because the vertical stress gradient can vary both between different basins, and with depth in the same basin.

Vertical stress magnitude was determined using data from Burley-2 because the density log in Burley-2 was run from near surface (approximately 787 ft bKB). In the other wells in the Nappamerri Trough, the density log was only run from below around 6000-7000 ft. The density log data from Burley-2 were edited to remove unreliable data (eg. due to bad hole condition and data spikes), then integrated according to Equation 3.1. The overburden stress trend was extrapolated to the surface over the approximately 800 ft for which no density data are available. The resultant vertical stress profile is shown on Figure 3.1. The vertical stress profiles equivalent to gradients of 0.9, 1.0 and 1.1 psi/ft are also shown for reference. Table 3.1 summarises the vertical stress magnitudes and equivalent stress gradients at key horizons in Burley-2.

Figure 3.1 Vertical stress profile for Burley-2.



	Depth (ft bGL)	Vertical Stress (MPa)	Vertical Stress Gradient (psi/ft)
top Nappamerri	7461	49.4	0.96
top Toolachee	8748	59.6	0.99
top Daralingie	9272	63.4	0.99
top Patchawarra	10 466	72.8	1.01
top Basement	11 998	84.7	1.02

Table 3.1 Vertical stress magnitudes and gradients for key horizons in Burley-2.

3.2 Vertical Stress Magnitude in the Nappamerri Trough

Figure 3.1 and Table 3.1 illustrate that the vertical stress gradient is not constant in the Nappamerri Trough and increases with depth due to the increase in density of the overburden with depth. In Burley-2 the overburden stress gradient increases from approximately 0.8 psi/ft near surface to 0.96 psi/ft at the base of Eromanga Basin sequence. The value increases from 0.96 psi/ft at the top of the Cooper Basin sequence (top Nappamerri group) to 1.02 psi/ft at the base of the Patchawarra Formation.

Only major lateral changes in stratigraphy, such as are not seen in the Nappamerri Trough, would cause the overburden stress gradient to vary at the same stratigraphic level within the basin, and the values for Burley-2 (Table 3.1) can be applied with reasonable confidence to the entire Trough. The classic overburden stress value of 1.0 psi/ft does indeed provide a reasonable approximation to the vertical stress gradient in the Cooper Basin of the Nappamerri Trough. However, the variation of the values at the different stratigraphic levels is significant and should be considered, for example, when planning fracture stimulation of the tight gas sands in the Trough.

4. Horizontal Stress Magnitude and Pore Pressure in the Nappamerri Trough

4.1 Introduction

The analysis of horizontal stress magnitudes herein is limited to that based on leak-off tests (LOT) and formation integrity tests (FIT). As such, horizontal stress magnitudes in the Nappamerri Trough are, as is often the case, the most poorly constrained aspect of the contemporary stress field. Ideally, horizontal stress magnitudes would be determined from hydraulic fracture-type (eg. minifrac) tests or on extended leak-off tests (Kunze & Steiger, 1991; Enever et al., 1996). However, such data are not routinely acquired in exploration wells and were not available for this study. Thus analysis herein is limited to that based on LOTs and FITs.

Section 4.2 outlines the procedures for and limitations of the data resulting from LOTs and FITs. Section 4.3 discusses the results of these tests in the Trough. Section 4.4 discusses pore pressures in the Trough and the intimate link between overpressures and high horizontal stresses. Section 4.5 uses the occurrence of breakouts and tensile fractures to put a lower limit on σ_{hmax}. Finally, given that detailed application of stress data to problems such as hydraulic fracturing or wellbore stability would require more detailed analysis of in situ horizontal stress magnitudes than can be undertaken herein, Section 4.6 discusses techniques for better defining horizontal stress magnitudes in the Trough.

4.2 Leak-Off and Formation Integrity Tests

An LOT is often undertaken at the beginning of a new drilling run in order to determine the fracture gradient; ie. the maximum mud weight that the wellbore can withstand without hydraulically fracturing. In an LOT the cement at the base of the casing is drilled out and the well is deepened a few metres. At this point borehole fluid pressures are increased by pumping additional mud into the well. Assuming that the cement job at the base of the casing remains intact, the mud begins to 'leak-off' when a fracture is initiated in the wellbore wall. Fracture initiation involves overcoming the circumferential stress acting at the borehole wall (Section 2.1), as well as any tensile strength that the rocks possess. Consequently LOPs tend to be higher than the least principal stress affecting the surrounding rocks (Bell, 1990). Although recognising that they do commonly exceed σ_{hmin}, typically by 5-10%, LOPs have been widely taken as a proxy for σ_{hmin} (Breckels & van Eekelen, 1982; Gaarenstroom et al., 1993; Caillet et al., 1997). In the absence of other data, LOPs are taken as a proxy for σ_{hmin} herein.

An FIT is similar to an LOT except that mud weight is only taken to a pre-determined limit and the wellbore wall is not fractured. Accepting leak-off pressures (LOPs) as a proxy for σ_{hmin}, formation integrity pressures (FIPs) are only useful in that they give a lower limit for σ_{hmin}. Unfortunately, only FITs are available in the Nappamerri Trough wells. In order to better constrain σ_{hmin} in the area, LOPs from wells surrounding the Nappamerri Trough have also been compiled. There is some confusion in well completion reports between LOTs and FITs, and only tests where leak-off is believed to have occurred have been classified as LOTs herein.

4.3 Minimum Horizontal Stress Magnitude in the Nappamerri Trough

Leak-off pressures were compiled from 24 wells surrounding the Nappamerri Trough (Figure 4.1 and Appendix I). These LOPs lie on a fairly consistent trend and a linear best fit fracture gradient/σ_{hmin} relation (with a correlation co-efficient of 0.98) is given by:

$$\sigma_{hmin} \approx 0.0056z - 1.5 , \qquad (4.1)$$

where σ_{hmin} is in MPa and z is depth in feet. At depths over 3 500 ft this is approximately equal to 0.8 psi/ft (Figure 4.1).

Four FIPs have been recorded in Nappamerri Trough wells (Figure 4.2 and Appendix I). The FIPs from the Nappamerri Trough are from greater depth than the LOPs but lie on the same 0.8 psi/ft trend (±0.1 psi/ft) as the shallower LOPs. However, given that FIPs provide a

Figure 4.1 Leak-off pressures (LOPs) and drilling mud weights from wells surrounding Nappamerri Trough. No LOPs available for the Nappamerri Trough wells in which only formation integrity tests were undertaken.

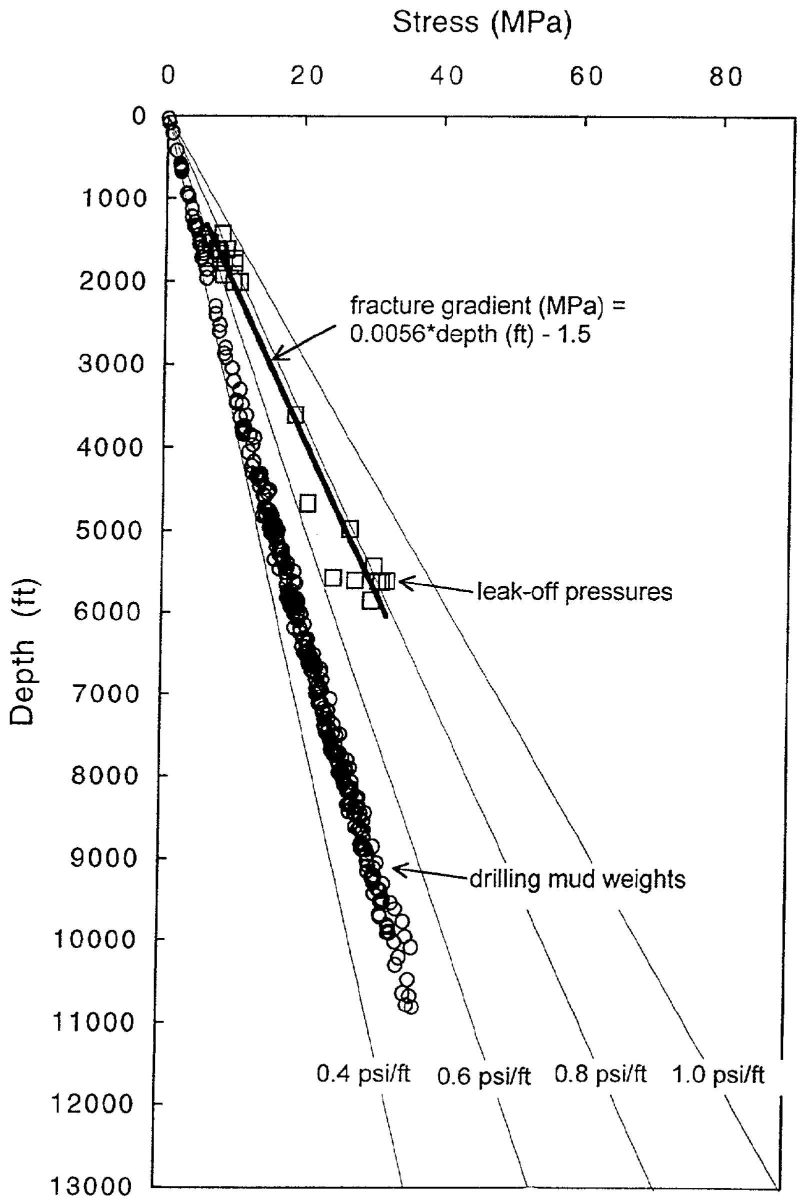
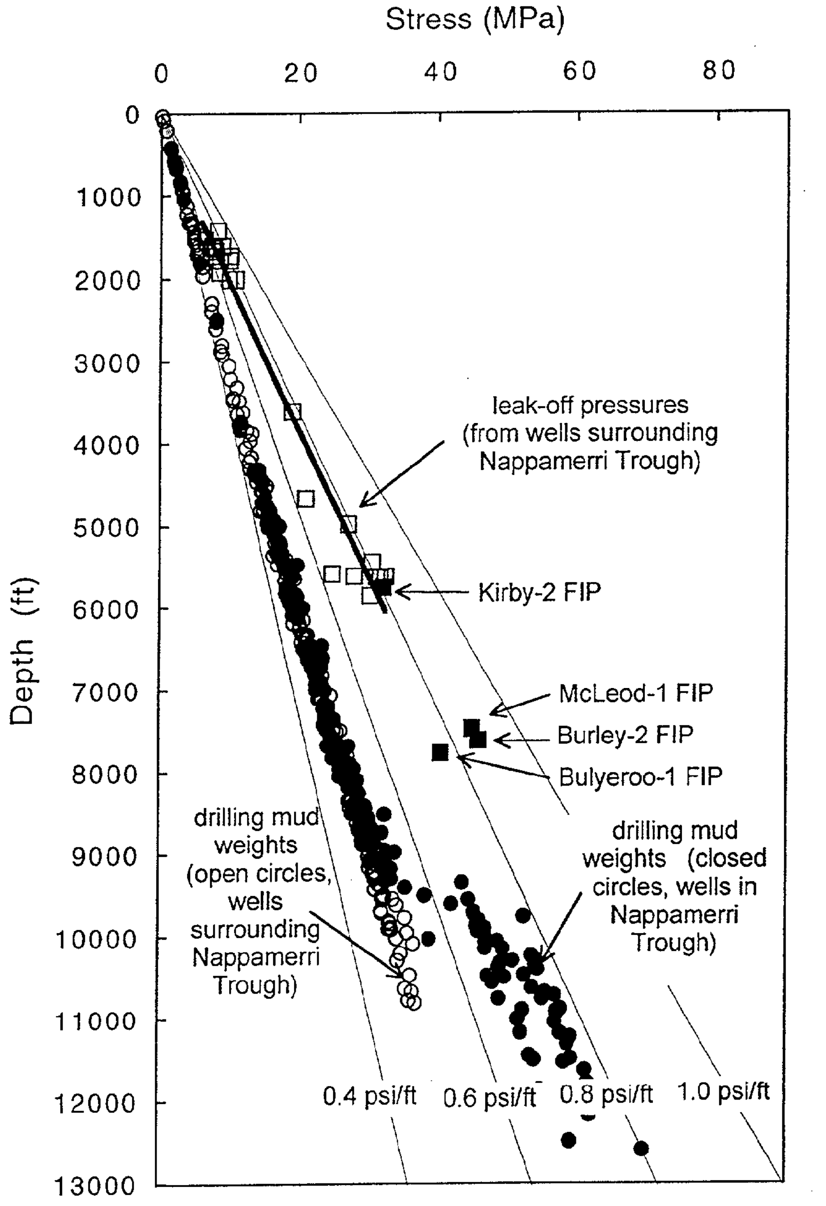


Figure 4.2 Formation integrity pressures (FIPs) and drilling mud weights from Nappamerri Trough wells. Leak-off pressures and drilling mud weights from wells surrounding the Nappamerri Trough.



lower limit for σ_{hmin}, the 0.8 psi/ft trend provides only a lower limit a lower limit for σ_{hmin} within the Trough.

4.4 Pore Pressures in the Nappamerri Trough

The mechanical behaviour of porous rocks is determined not by the applied, total stress, but by the effective stress (Handin et al., 1963). Effective stress is the difference between the applied, total stress and pore pressure. Hence the determination of pore pressures is a crucial part of the evaluation of the contemporary stress field. Furthermore, there is an intimate link between elevated pore pressures and high horizontal stresses (Teufel et al., 1991) which is of major significance to the tight gas resources in the Nappamerri Trough.

Mud weights give a crude indication of pore pressures in that they are generally maintained somewhat in excess of pore pressures to prevent kicks. Elevated pore pressures are invariably reflected by elevated mud weights. However, the converse is not always true because mud weights are also raised to ameliorate mechanical instability of the wellbore, specifically borehole breakout.

Mud weights for the wells surrounding the Nappamerri Trough from which LOPs were obtained indicate that pore pressures are essentially hydrostatic; ie. approximately 0.45 psi/ft for pore water of normal marine salinity (Figure 4.1 and Appendix II). However, for wells within the Trough there is a marked increase in mud weights at around 9500 ft from approximately 0.5 psi/ft equivalent to approximately 0.7 psi/ft (Figure 4.2 and Appendix II). Maximum mud weights in the Nappamerri Trough reach approximately 0.8 psi/ft. An increase in background gas, and connection gas from the top of the Patchawarra Formation in Bulyeroo-1 indicates that pore pressure is close to the mud weight and confirms that in Bulyeroo-1 at least high mud weight is reflecting overpressure.

Total horizontal stress is not independent of pore pressure and in general as pore pressure increases, total horizontal stress increases. However, overpressure development does not significantly affect the total vertical stress, largely because the earth's surface is a free surface. This phenomenon has been observed in both the Canadian Scotian Shelf and North Sea (Yassir and Rogers, 1993; Grauls, 1997). In these areas, at shallow depths and near hydrostatic pore pressures, the vertical stress is the maximum principal stress (ie. $\sigma_V > \sigma_{hmax} > \sigma_{hmin}$: extensional stress regime), but at greater depths and elevated pore pressures the horizontal stresses increase with respect to the vertical stress which becomes the intermediate or even minimum principal stress (ie. $\sigma_{hmax} > \sigma_V > \sigma_{hmin}$: strike-slip stress regime; or $\sigma_{hmax} > \sigma_{hmin} > \sigma_V$: compressional stress regime).

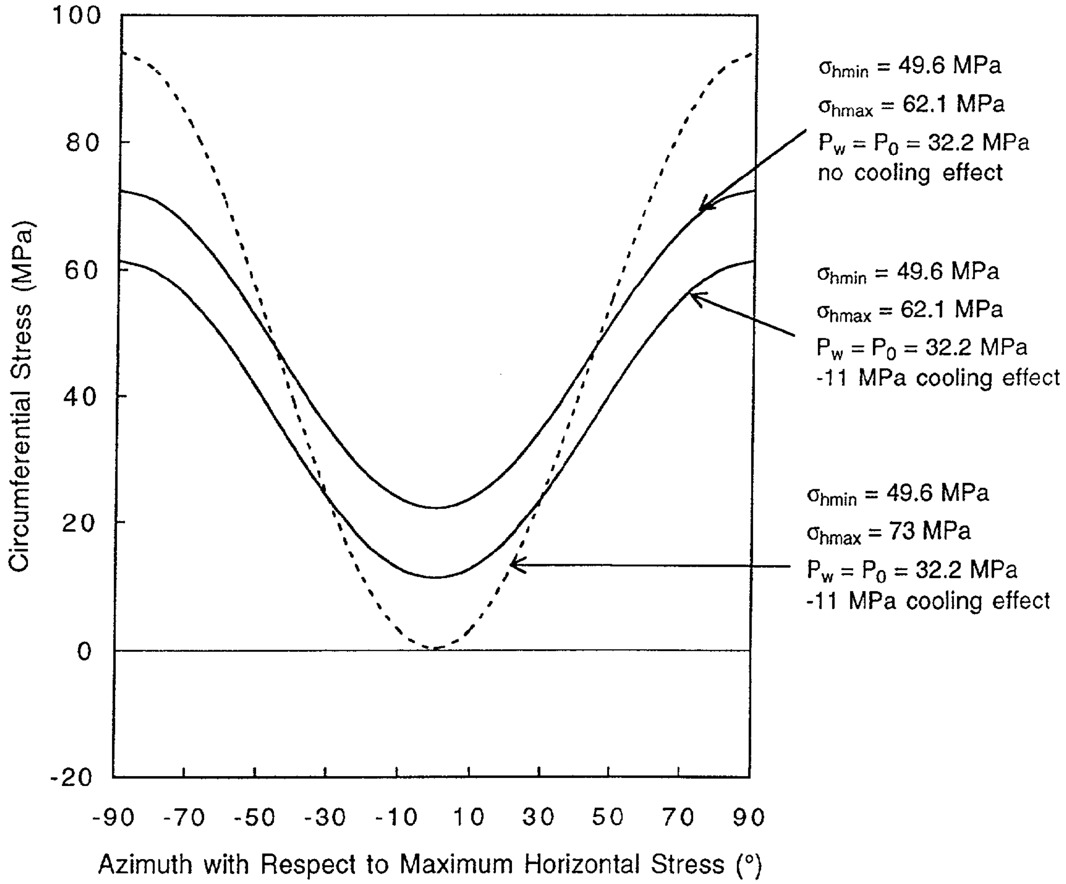
Unfortunately there are not even FITs available from the overpressured parts of the Nappamerri Trough. However, given the increase in σ_{hmin} that is observed with overpressure development worldwide, it is likely that in the overpressured Nappamerri Trough σ_{hmin} exceeds the 0.8 psi/ft trend associated with shallow, normally pressured areas and becomes close to, and possibly greater than σ_V. As discussed in Chapter 6 this has very significant implications for the exploitation of the tight gas resource in the Trough.

4.5 Maximum Horizontal Stress Magnitude in the Nappamerri Trough

The occurrence of tensile fractures in the wells for which FMS data were analysed within the Nappamerri Trough can be used to place a lower limit on σ_{hmax}. This analysis aims to demonstrate that the occurrence of tensile fractures is inconsistent with σ_{hmax} magnitudes less than those of σ_V, and hence that an extensional stress regime ($\sigma_V > \sigma_{hmax} > \sigma_{hmin}$) is not likely to be encountered in the Trough.

As discussed in Section 4.2, the lower limit of σ_{hmin} in the Nappamerri Trough is given by 0.8 psi/ft. Considering a typical depth of 9 000 ft at which both breakouts and tensile fractures are observed, this equates to 49.6 MPa (7 200 psi). The vertical stress at the same depth is approximately 62.1 MPa (9 000 psi). Assuming σ_{hmin} is 49.6 MPa and σ_{hmax} is

Figure 4.3 Circumferential stresses around a wellbore for various stress conditions.
Cooling effect is tensional stress imparted by drilling muds cooler than rocks forming the wellbore wall.
See text for discussion.



equal to σ_V, the circumferential stress acting around a vertical wellbore can be calculated from Equation 2.1 (Figure 4.3). Figure 4.3 assumes a typical drilling mud weight of 10 ppg (32.2 MPa at 9 000 ft), and that this mud weight is in balance with the formation pore pressure. Given these conditions, the minimum circumferential stress acting at the wellbore wall is approximately 22.3 MPa, and tensile fractures would not form. In order for tensile fractures to form, the minimum circumferential stress must be less than the tensile strength (which has a maximum value of zero).

The thermal effects of cool drilling mud contacting hot formation rocks forming the wellbore wall must also be considered. Cooler drilling mud imparts a tensional circumferential stress ($\Delta\sigma_{\theta\theta}$) on the wellbore wall:

$$\Delta\sigma_{\theta\theta} = \frac{\alpha E \Delta T}{1 - \upsilon}, \qquad (4.2)$$

where α is the coefficient of thermal expansion (5×10^{-6} °C^{-1}), E is Young's modulus (3.5×10^4 MPa), ΔT is the temperature contrast between the drilling mud and the formation, and υ is Poisson's ratio (0.2). Equation 4.2 and the values quoted (average sandstone) are from Turcotte and Schubert (1982). Using these values the tensional circumferential stress is 0.22 MPa per °C temperature contrast. Determining the temperature contrast is problematic. However, cooler downgoing muds inside the drill string are heated by upcoming warmer muds in the annulus, and when the drill pipe is rotated turbulent fluid boundary layers are produced inside and outside the drillpipe, allowing large radial heat transfer (Guenot & Santarelli, 1989). Even in the hot Nappamerri Trough, it is unlikely that this temperature contrast is in excess of 50°C, and usually much lower values are used (eg. 10°C; Moos & Zoback, 1990). A temperature contrast of 50°C equates to 11 MPa of tensional circumferential stress. This value is insufficient to generate the observed tensile fractures for the stress conditions discussed above (Figure 4.3).

For the σ_{hmin}, drilling mud and pore pressure values above, and allowing for -11 MPa cooling effect, the minimum circumferential stress only drops to zero when σ_{hmax} reaches 73 MPa, significantly greater than σ_v at 9 000 ft (Figure 4.3). Hence the occurrence of tensile fractures in the wells for which FMS logs were analysed in the Nappamerri Trough suggests that σ_{hmax} is in excess of σ_v, and thus an extensional stress regime is unlikely to be encountered. The above analysis used the lower limit for σ_{hmin} in the Trough. Higher values of σ_{hmin} would need concomitantly higher values of σ_{hmax} to generate tensional fractures, hence as suggested above, an extensional stress regime is unlikely to be encountered.

4.6 Improved Horizontal Stress Magnitude Determination

Horizontal stress magnitudes are usually, as is the case in this study, the worst constrained aspect of the contemporary stress field. In situ application of contemporary stress field data to fracture stimulation and wellbore stability requires in situ horizontal stress magnitude data beyond that determined herein. Nonetheless, as discussed in Chapter 6, some important conclusions can be drawn from the available data. This section summarises methods that could, with more data, be applied to better constrain horizontal stress magnitudes in the Nappamerri Trough.

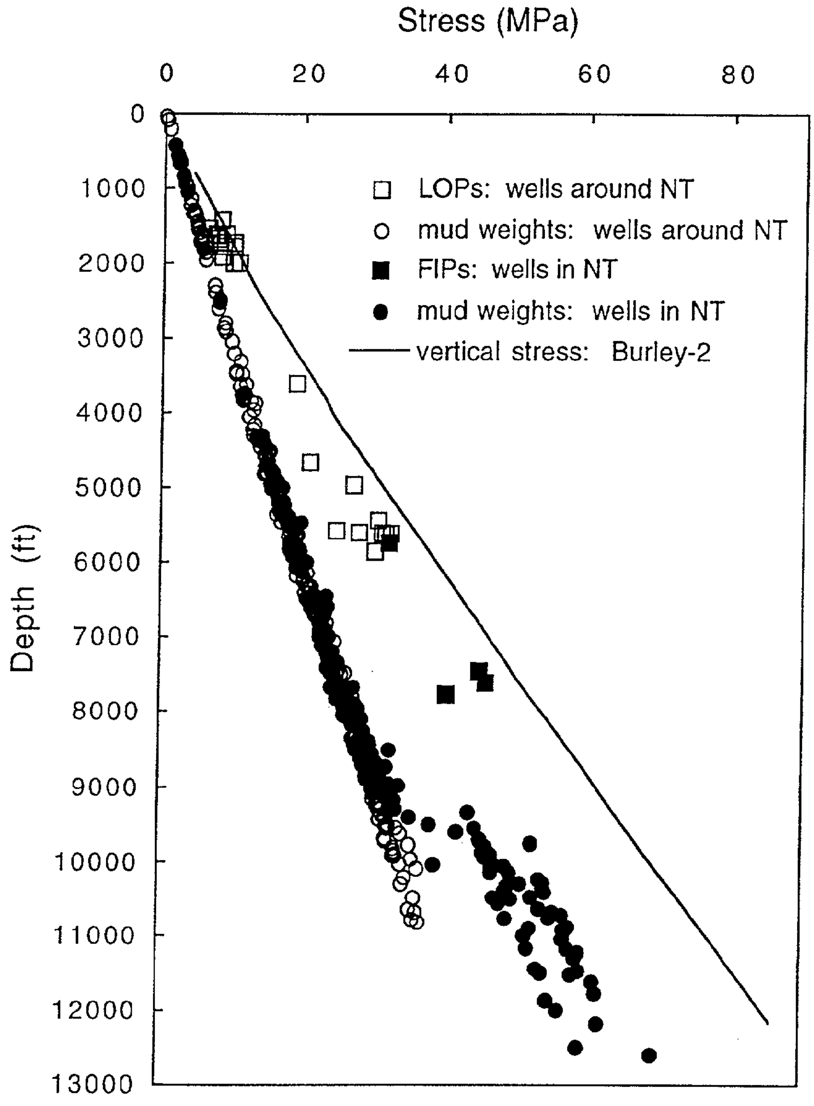
Although LOTs can provide an estimate of σ_{hmin}, they cannot be used to determine σ_{hmax}. High quality hydraulic fracture-type tests can be used to determine σ_{hmax} magnitude. Extended leak-off tests represent a compromise between a full hydraulic fracture test and the commonly undertaken leak-off test and can yield valuable data for constraining horizontal stress magnitudes (Kunze & Steiger, 1991; Enever et al., 1996). These data are not currently available for the Nappamerri Trough. Other techniques for constraining σ_{hmax} include combining information on minimum horizontal stress magnitude with that on breakout and/or tensile fracture occurrence and rock strengths (eg. Moos and Zoback, 1990; Vernik & Zoback, 1992; Zhou, 1997), or analysing the variation of breakout direction or LOP with the angle of deviation and azimuth in deviated wells (Aadnoy, 1990; Peska & Zoback, 1995;

Etchecopar/Schlumberger, unpublished). The requisite data for such analyses were not available for this study.

5. Summary of the Stress Field of the Nappamerri Trough

The stress field of the Nappamerri Trough area is summarised in Figure 5.1. Maximum horizontal stress is oriented approximately east-west in and around the Nappamerri Trough. The vertical, overburden stress gradient in the Nappamerri Trough increases from 0.96 psi/ft at the top of the Cooper Basin sequence to 1.02 psi/ft at the base of the Patchawarra Formation. The magnitude of σ_{hmin} in the Eromanga Basin sequence surrounding the Trough is approximately 0.8 psi/ft. In the Trough itself, between 6 000 and 9 000 ft, formation integrity pressures lie approximately on the 0.8 psi/ft trend, and σ_{hmin} magnitude is underconstrained, but probably somewhat in excess of 0.8 psi/ft. Overpressures, approaching 0.8 psi/ft are observed in the Trough at depths of in excess of 9 000 ft. In overpressured zones σ_{hmin} is likely to be close to or may even exceed the overburden gradient of approximately 1 psi/ft. The magnitude of σ_{hmax} is poorly constrained in the Nappamerri Trough, but the occurrence of tensile fractures suggests that it is in excess of σ_V.

Figure 5.1 Summary of the stress regime of the Nappamerri Trough (NT).
LOPs: leak-off pressures; FIPs: formation integrity pressures.



6. Implications for Tight Gas Resources

6.1 Open Natural Fracture Orientations and Naturally Fractured Plays

Given the low porosity and low permeability of tight gas sands in the Nappamerri Trough, naturally fractured zones represent important potential 'sweet spots' of improved permeability (and to a lesser extent improved porosity). Horizontal and deviated wells play a major role in the exploitation of naturally fractured reservoirs because most fractures sets are steeply dipping, and therefore horizontal wells can intersect more fractures, and be more productive than vertical wells. Knowledge of the contemporary stress field is of major significance in assessing which fracture trends are most likely to be open and productive, and which closed and unproductive, and therefore in planning the azimuth of deviated and horizontal wells.

Pre-existing natural fractures orthogonal to σ_{hmin} are subject to the least effective normal stress and hence are the most likely to be open and productive, whilst those orthogonal to σ_{hmax} tend be closed and non-productive, as has been demonstrated in the naturally fractured Austin Chalk of Texas (Horn, 1991). Thus any east-west striking and steeply dipping fractures in the Nappamerri Trough are the most likely to be open and productive. Conversely, north-south natural fractures, aligned orthogonal to σ_{hmax} in the Nappamerri Trough, are likely to be closed and unproductive. Hence horizontal wells designed to maximise intersection with open natural fractures should be deviated north-south in the Nappamerri Trough.

The co-existence of both breakouts and tensile fractures in several wells in the Nappamerri Trough area is indicative of a relatively large horizontal stress anisotropy. Hence the orientation of the horizontal stresses is likely to play a significant role in open, natural fracture orientation in the Nappamerri Trough, more so than when the horizontal stresses are relatively isotropic (Hillis, 1997).

The above argument is somewhat simplistic in that it ignores the stiffness, or resistance to closure of natural fractures. If a fracture is in hard rock and/or is partially mineralised, it may remain open despite being subjected to relatively high effective normal stresses, as is seen at least locally in the Palm Valley Field of central Australia (Berry et al. 1996). Hillis (1997) discussed in detail the closure of pre-existing natural fractures with reference to the anisotropy of the stress field, fracture stiffness and fracture orientation. Nonetheless, in the Nappamerri Trough, where pre-existing fracture orientation is unknown, wells should, as suggested above, be deviated in the north-south, σ_{hmin} direction in order maximise intersection with open natural fractures. Only where there is demonstrable evidence for pre-existing, stiff fractures remaining open at a high angle to the σ_{hmax} direction, should wells be deviated in that direction to maximise intersection with open fractures.

Regional, systematic fracture sets in otherwise little-deformed strata are an important class of fractures in reservoir rocks that are distinct from the more widely described fault- and fold-related fractures (eg. Lorenz et al., 1991). Although their origin as natural hydraulic fractures is not unanimously accepted, it is clear that they are dilational fractures associated with overpressures, and that they are oriented orthogonally to σ_{hmin}. Such fractures are of particular interest to tight gas exploration in the Nappamerri Trough. They have been described in the Mesaverde tight gas reservoirs of the Piceance Basin, Colorado, where they have been intersected with a slant hole and result in a horizontal permeability anisotropy of 100:1 (Lorenz & Finley, 1991). The regional fracture set in the Mesaverde reservoir is interpreted to have formed 36-40 Ma, but their west-northwest strike is parallel to the contemporary σ_{hmax} direction. By analogy with the Piceance basin, overpressures in the deep Nappamerri Trough may have been, and may still be, conducive to the formation of such fractures. In order to utilise the permeability anisotropy associated with such fractures, deviated and horizontal wells should be drilled in a northerly or southerly azimuth.

The gas discoveries at Lycosa-1 and Moolalla-1, southwest of the Nappamerri Trough, in the vicinity of Daralingie Field, indicate the potential for naturally fractured plays in the Cooper Basin (Taylor et al., 1991). Lycosa-1 achieved a maximum gas flow of 5 MMCFD from fractured basement and Moolalla-1 flowed 9.6 MMCFD from a fractured unit of either basement or Merrimelia Formation affinities. The productive section at Lycosa-1 shows open fractures which provide permeability with gas reservoired in low porosity (3-4%) units. In contrast, Moolalla-1 has moderate porosities (around 10%) in sands with permeabilities possibly enhanced by fracturing. Natural fractures in the lower Patchawarra - basement of Moomba-73 (Section 2.4) further confirm the potential of this play. In all three cases these fractures are more consistent with an origin as fault- and fold-related fractures than as regional fracture sets, and the significance of the contemporary stress field is in its tendency to preferentially close pre-existing fractures oriented at a high angle to σ_{hmax}. The probability of the vertical wells drilled to-date in the Nappamerri Trough intersecting a vertical regional fracture set of the type seen in the Piceance Basin in relatively small, and such regional fracture sets are only likely to be intersected by deviated wells.

6.2 Fracture Stimulation

Fracture stimulation is likely to be a key technique for attempting to unlock the massive gas resource of the Nappamerri Trough from the low porosity, low permeability reservoirs of the area. Unfortunately, the FMS analysis of Section 2.6 indicates that fracture stimulation in the Nappamerri Trough is likely to be more problematic than in areas where simple, planar fractures are formed. The observed multiple, dipping fractures offset along horizontal laminations are likely to result in complex and tortuous fracture networks, and thus high treatment pressures, poor proppant transport and screenout (for further discussion see Warpinski & Teufel, 1987).

Clearly it is desirable to select as homogeneous a formation as possible for stimulation. The horizontal laminae, interpreted to be coals, along which drilling-induced tensile fractures terminate or are offset are deleterious to fracture propagation, and intervals with the minimum of such laminations are likely to be more successfully fracture stimulated.

Given that fractures typically traverse the wellbore for of the order of 1 ft, as many as 50 fractures may be generated in a 50 ft stimulation interval. Such multiple fractures are harder to propagate to the desired distance from the wellbore than a single fracture because pressure is dissipated in multiple fractures, and because the multiple fractures act against each other's further opening. Multiple fractures are less likely to occur if the fractures are axial to the wellbore. Thus slightly inclined wellbores, parallel to the dip of the fractures, should be less subject to the generation of multiple fractures. Alternatively stimulation of east-west horizontal wellbores may result in axial fractures. It is recommended that image log data such as that from the FMS tool be obtained prior to fracturing, in order to investigate both the homogeneity of the formation, and the extent to which stimulation fractures are likely to be axial to the wellbore. Alternatively multiple fracture development may be inhibited by fracturing from a pseudo-point source.

Where overpressures are developed in the Nappamerri Trough, σ_{hmin} is likely to approach and may even exceed σ_v (Section 4.4). If σ_{hmin} exceeds σ_v the stress regime is compressional ($\sigma_{hmax} > \sigma_{hmin} > \sigma_v$). Such high horizontal stresses are likely to exacerbate problems associated with fracture stimulation in the Nappamerri Trough. If σ_{hmin} is greater than σ_v, hydraulic fractures are likely to be horizontal and may enhance production less than vertical fractures if horizontal permeabilities are greater than vertical permeabilities (as is often associated with the presence of clay minerals). Furthermore if horizontal fractures are generated in a vertical well, there is a strong possibility of inducing multiple fractures with the deleterious effects described above.

Where σ_{hmin} is greater than σ_v, fractures may form vertically at the wellbore (due to stress concentration effects at the wellbore wall), but twist to their geomechanically-preferred horizontal orientation as they propagate away from the wellbore. Such twisting is likely to be associated with loss of fracture conductivity, and potential difficulty in proppant placement. Furthermore, where σ_{hmin} is greater than σ_v, but vertical fractures are created at the wellbore wall (due to stress concentration effects), with increased pressure drop/friction pressure along the propagating fractures, increased pressure in the wellbore may result in the formation of a second generation of horizontal fractures at the wellbore wall. This scenario leads to a tortuous fracture network with possible loss of fracture conductivity, and difficulty in placing proppant.

As discussed in Section 4.4, total horizontal stress is not independent of pore pressure, and as pore pressure decreases due to reservoir depletion, total horizontal stress decreases (Teufel et al., 1991). However, changes in pore pressure do not significantly affect the total vertical stress. Hence with depletion, σ_{hmin} can be reduced with respect to σ_v. Where possible, depletion of overpressured reservoirs prior to fracture stimulation should ameliorate problems associated with the stimulation of overpressured reservoirs.

The above provides significant input to the planning of fracture stimulation in the Nappamerri Trough. However, stimulation requires extensive in situ stress testing, beyond that which can be undertaken using a standard exploration database such as was available for this study. For example, in situ stress testing is necessary in the well to be stimulated in order to determine σ_{hmin} contrasts between different lithologies, and thereby assess fracture growth and containment.

6.3 Wellbore Stability

Caliper logs from the HDT and FMS tools reveal extensive wellbore instability in the Nappamerri Trough, largely associated with borehole breakout (Section 2.5). Borehole instability adversely affects drilling time and costs, and log quality. This section addresses wellbore stability in the context of the contemporary stress field, with particular reference to deviated and horizontal drilling which is likely to play a roll in unlocking the tight gas resource of the Nappamerri Trough. Although conclusions can be drawn on most stable drilling directions, detailed applications such as predicting optimum mud weight for a given drilling direction require data beyond that available for this study. For such predictions, the magnitude of σ_{hmax} would need to be determined (using techniques such as those outlined in Section 4.6), and strength testing of the various lithologies in the Trough undertaken.

Purely from a mechanical perspective (and ignoring for example the possible effect of increased mud weight on invasion and in turn on rock strength), increased mud weight should inhibit breakout formation in the Nappamerri Trough. However, tensile fractures are also present in most wells (Section 2.4). Hence increasing mud weights beyond those used in the wells analysed is likely to lead to mud losses. Given the contemporary stress field of the Nappamerri Trough area, there appears to be no 'safe' mud weight at which both breakout and tensile fracture are successfully inhibited. This is typical of areas with a fairly high stress anisotropy (ie. large difference between σ_{hmax} and σ_{hmin}). Mud weight selection should be based on an assessment of the relative disadvantages of tensile fractures/poor hole quality to the objectives of the well. Although not addressed in this report, the case for improved wellbore stability through increased mud weight must be balanced against the associated potential for increased formation damage to the low porosity/low permeability reservoirs.

Hillis & Williams (1993) discussed horizontal wellbore stability in the extensional ($\sigma_v > \sigma_{hmax} > \sigma_{hmin}$), strike-slip ($\sigma_{hmax} > \sigma_v > \sigma_{hmin}$) and compressional ($\sigma_{hmax} > \sigma_{hmin} > \sigma_v$) stress regimes. The principles outlined by Hillis & Williams (1993) are applied here to the likely range of stress regimes in the Nappamerri Trough. In areas with the lowest horizontal stresses (normally pressured areas surrounding the Trough) it is inferred that: $\sigma_{hmin} < \sigma_v \approx \sigma_{hmax}$; ie. the stress regime is approximately on the boundary of extension and strike-slip (Chapter 5). In areas with the highest horizontal stresses (overpressured areas within the Trough) it is inferred that $\sigma_{hmin} \approx \sigma_v < \sigma_{hmax}$; ie. the stress regime is approximately on the boundary of strike-slip and compression (Chapter 5). These two scenarios represent the limiting conditions of the strike-slip stress regime. Hence by considering horizontal wellbore stability through the entire strike-slip stress regime, the conditions likely to be encountered in the Nappamerri Trough are represented (although it is recognised that the stress regime may pass from strike-slip into compressional in areas of high horizontal stresses).

One important, and perhaps counter-intuitive, aspect of horizontal wellbore stability in the strike-slip stress regime is that horizontal wellbores of any azimuth should be more stable than vertical wellbores, drilling and rock strength parameters being constant. In the strike-slip stress regime $\sigma_{hmin} < \sigma_v < \sigma_{hmax}$, hence a vertical well (which is subject to the two horizontal stresses) is subject to maximum stress anisotropy and therefore the maximum stress concentration around the wellbore. Hence drilling and rock strength parameters being constant, horizontal wellbores in the Nappamerri Trough are not considered likely to be any more prone to wellbore instability than vertical wells, as is often assumed to be the case. Indeed suitably oriented horizontal wellbores should be less prone to instability than vertical wells.

There is always a horizontal drilling direction within the strike-slip stress regime that is subject to zero stress anisotropy. This is the most stable drilling direction. At one extreme of the strike-slip stress regime, where $\sigma_{hmin} < \sigma_v \approx \sigma_{hmax}$ (the boundary with the extensional stress regime), a well drilled in the azimuth of σ_{hmin} is the most stable. Hence in areas with lowest horizontal stresses (normally pressured areas surrounding the Trough) north-south oriented horizontal wellbores would be the least prone to breakout and require the minimum mud weight. At the other extreme of the strike-slip stress regime, where $\sigma_{hmin} \approx \sigma_v < \sigma_{hmax}$ (the boundary with the compressional stress regime), a well drilled in the azimuth of σ_{hmax} is the most stable. Hence in areas with highest horizontal stresses (overpressured areas within the Trough) an east-west oriented horizontal wellbore would be the least prone to breakout and require the minimum mud weight.

As the stress field progressively becomes more compressional and changes from $\sigma_{hmax} \approx \sigma_v$ to $\sigma_{hmin} \approx \sigma_v$, the most stable drilling direction progressively changes from σ_{hmin} to σ_{hmax}. In the compressional stress regime ($\sigma_v < \sigma_{hmin} < \sigma_{hmax}$, which may be attained in deep overpressured parts of the Trough) the horizontal wells should be drilled in the direction of σ_{hmax} for maximum stability In general the more compressive the stress regime (ie. the higher the horizontal stresses) the more likely breakout is to occur, and thus wellbore instability is likely to be more of a problem in the deep overpressured Trough than in the normally pressured flanks. This is consistent with the observation that in those for which FMS data were analysed, Bulyeroo-1 was subject to the greatest instability, despite having been drilled with the highest mud weight (Section 2.5).

The east-west horizontal drilling direction which minimises the propensity for breakout in the deep overpressured Trough may be a suitable deviation direction if the well is to be fracture stimulated. As discussed in Section 6.2 it is inferred that fractures stimulated in such a well would be steeply dipping and axial to the wellbore. However, if σ_{hmin} is equal to or greater than σ_V, stimulation fractures may be horizontal or twist to horizontal away from the wellbore. Thus if the reservoir is strongly overpressured, pore pressure depletion should, if possible, be considered prior to fracturing. The east-west drilling orientation is a poor one for intersecting pre-existing open natural fractures.

The north-south horizontal drilling direction which minimises the propensity for breakout in normally pressured areas surrounding the Trough is not an ideal orientation for fracture stimulation in the Trough, because it is likely to be subject to multiple fracture generation and fracture twisting. Conversely, this a good drilling direction for intersecting pre-existing open natural fractures. Clearly the final choice of drilling direction depends on the primary objectives of the well.

7. References

Aadnoy, B.S., 1990. Inversion technique to determine the in-situ stress field from fracturing data. *Journal of Petroleum Science and Engineering*, **4**, 127-141.

Bell, J.S., 1990. Investigating stress regimes in sedimentary basins using information from oil industry wireline logs and drilling records. In: Hurst, A., Lovell, M.A. & Morton A.C. (eds) *Geological Applications of Wireline Logs*. Geological Society London Special Publication, **48**, 305-325.

Berry, M.D., Stearns, D.W. & Friedman, M., 1996. The development of a fractured reservoir model for the Palm Valley gas field. *Australian Petroleum Production and Exploration Association Journal*, **36**, 82-103.

Breckels, I.M. & van Eekelen, H.A.M., 1982. Relationship between horizontal stress and depth in sedimentary basins. *Journal of Petroleum Technology*, **34**, 2191-2198.

Caillet, G., Judge, N.C., Bramwell, N.P., Meciani, L., Green, M. & Adam, P., 1997. Overpressure and hydrocarbon trapping in the Chalk of the Norwegian Central Graben. *Petroleum Geoscience*, **3**, 33-42.

Dart, R.L. & Zoback, M.L., 1989. Wellbore breakout stress analysis within the central and eastern continental United States. *Log Analyst*, **30**, 12-25.

Dickinson, G., 1953. Geological aspects of abnormal reservoir pressures in Gulf Coast Louisiana. *American Association of Petroleum Geologists Bulletin*, **37**, 410-423.

Enever, J.R., Yassir, N., Willoughby, D.R. & Addis, M.A., 1996. Recent experience with extended leak-off tests for in-situ stress measurements in Australia. *Australian Petroleum Production and Exploration Association Journal*, **36**, 528-535.

Gaarenstroom, L., Tromp, R.A.J., de Jong, M.C. & Brandenburg, A.M., 1993. Overpressures in the Central North Sea: implications for trap integrity and drilling safety. In: Parker, J.R. (ed) *Petroleum Geology of Northwest Europe*: Proceedings of the 4th Conference, **2**, 1305-1313, The Geological Society, London.

Grauls, D.J., 1997. Minimum principal stress as control of overpressures in sedimentary basins: significance and implications. In: *Geofluids II*, extended abstracts of the Geofluids II Conference, Belfast, 1997.

Guenot, A. & Santarelli, F.J., 1989. Influence of mud temperature on deep borehole behavior. In: Maury, V. & Fourmaintraux, D. (eds) *Proceedings of the International Symposium on Rock at Great Depth*, **2**, 809-817.

Handin, J., Hager, Jr, R.V., Friedman, M. & Feather, J.N., 1963. Experimental deformation of sedimentary rocks under confining pressure: pore pressure tests. *American Association of Petroleum Geologists Bulletin*, **47**, 718-755.

Hillis, R.R., 1997. Does the in situ stress field control the orientation of open natural fractures in sub-surface reservoirs? *Exploration Geophysics*, **28**, 80-87.

Hillis, R.R., Monte, S.A., Tan, C.P. & Willoughby, D.R., 1995. The contemporary stress field of the Otway Basin, South Australia: implications for hydrocarbon exploration and production. *Australian Petroleum Exploration Association Journal*, **35**, 494-506.

Hillis, R.R. & Williams, A.F., 1993. The contemporary stress field of the Barrow-Dampier Sub-Basin and its implications for horizontal drilling. *Exploration Geophysics*, **24**, 567-576.

Horn, M.K., 1991. Play concepts for horizontal drilling. In: Fritz, R.D., Horn, M.K., & Joshi, S.D. (eds) *Geological Aspects of Horizontal Drilling*. American Association of Petroleum Geologists Continuing Education Course Note Series, **33**, 189-323.

Kunze, K.R. & Steiger, R.P., 1991. Extended leak-off tests to measure in situ stress during drilling. In: Roegiers, J.-C. (ed) *Rock Mechanics as a Multidisciplinary Science*. Balkema, Rotterdam, 35-44.

Lorenz, J.C., Teufel, L.W. & Warpinski, N.R., 1991. Regional Fractures I: A mechanism for the formation of regional fractures at depth in flat-lying reservoirs. *American Association of Petroleum Geologists Bulletin*, **75**, 1714-1737.

Lorenz, J.C. & Finley, S.J., 1991. Regional Fractures II: Fracturing of Mesaverde reservoirs in the Piceance Basin, Colorado. *American Association of Petroleum Geologists Bulletin*, **75**, 1738-1757.

Moos, D. & Zoback, M.D., 1990. Utilization of observations of well bore failure to constrain the orientation and magnitude of crustal stresses: application to Continental, Deep Sea Drilling Project, and Ocean Drilling Program boreholes. *Journal of Geophysical Research*, **95**, 9305-9325.

Peska, P. & Zoback, M.D, 1995. Compressive and tensile failure of inclined well bores and determination of in situ stress and rock strength. *Journal of Geophysical Research*, **100**, 12791-12811.

Plumb, R.A., & Hickman, S.H., 1985. Stress-induced borehole elongation: a comparison between the four-arm dipmeter and the borehole televiewer in the Auburn geothermal well. *Journal of Geophysical Research*, **90**, 5513-5521.

Prensky, S., 1992. Borehole breakouts and in situ rock stress. A review. *The Log Analyst,* **33**, 304-312.

Taylor, S., Solomon, G., Tupper, N., Evanochko, J., Horton, G., Waldeck, R. & Phillips, S, 1991. Flank plays and faulted basement: new directions for the Cooper Basin. *Australian Petroleum Exploration Association Journal*, **31**, 56-73.

Teufel, L.W., Rhett, D.W. & Farrell, H.E., 1991. Effect of reservoir depletion and pore pressure drawdown on in situ stress and deformation in the Ekofisk Field, North Sea. In: Roegiers, J.-C. (ed) *Rock Mechanics as a Multidisciplinary Science*. Balkema, Rotterdam, 63-72.

Turcotte, D.L. & Schubert, G., 1982. *Geodynamics: Applications of Continuum Physics to Geological Problems*. John Wiley & Sons, New York, NY, 450 pp.

Vernik, L. & Zoback, M.D., 1992. Estimation of maximum horizontal principal stress magnitude from stress-induced wellbore breakouts in the Cajon Pass scientific research borehole. *Journal of Geophysical Research*, **97**, 5109-5119.

Warpinski, N.R. & Teufel, L.W., 1987. Influence of geologic discontinuities on hydraulic fracture propagation. *Journal of Petroleum Technology*, **39**, 209-220.

Yassir, N.A. & Rogers, A.L., 1993. Overpressures, fluid flow and stress regimes in the Jeanne d'Arc Basin, Canada. *International Journal of Rock Mechanics and Mineral Science and Geomechanical Abstracts*, **30**, 1209-1213.

Zhou, S., 1997. A method of estimating horizontal principal stress magnitudes from stress-induced wellbore breakout and leak-off tests and its application to petroleum engineering. *Petroleum Geoscience*, 3, 57-64.

Zoback, M.L., 1992. First- and second-order patterns of stress in the lithosphere: the World Stress Map project. *Journal of Geophysical Research*, **97**, 11703-11728.

8. Acknowledgements

Many thanks to Tony Hill, Elinor Alexander and John Morton of MESA for assistance in accessing the requisite data on the Nappamerri Trough.

Appendix I: Leak-Off and Formation Integrity Pressures
from Wells Surrounding and Within the Nappamerri Trough.

Leak-Off Pressures (LOP) from Wells Surrounding the Nappamerri Trough

Well	Casing Shoe	Depth (ft)	LOP (ppg)	LOP (MPa)	Formation	Lithology
Bauhinia 1	9.625	1610	15.4	8.88	Winton	sltst
Cactus 1	9.625	1666	13.1	7.82	Winton	sst
Cowralli 3	9.625	5622	16.1	32.43	Cadna-Owie	sst/sltst
Deparanie 1	9.625	1725	9.4	5.81	Surficial	clst
Dullingari 46	9.625	4665	12.6	21.06	Cadna-Owie	sst/sltst
Gahnia 1	9.625	4975	15.2	27.10	Cadna-Owie	sltst
Gidgealpa 38	9.625	1535	11.6	6.38	Surficial	sltst/coal
Gidgealpa 39	9.625	1608	12.8	7.37	Winton	sltst
Gidgealpa 47	9.625	1425	16.1	8.22	Winton	clst
Gooranie 3	9.625	5634	15.7	31.69	Cadna-Owie	sltst
Haloragis 1	9.625	1724	16.3	10.07	Winton	clst
Kerna 5	9.625	1725	13	8.04	Winton	sst
Moomba 67	9.625	1776	13.4	8.53	Winton	sltst
Moomba 71	9.625	1777	15.7	10.00	Winton	clst
Moomba 72	9.625	5610	13.9	27.94	Cadna-Owie	sst
Moorari 8	9.625	5859	14.4	30.23	Cadna-Owie	sst/sltst
Napowie 1	9.625	5618	15.5	31.20	Cadna-Owie	sltst
Nappacoongee East 1	9.625	1921	12.1	8.33	Winton	sltst
Nardu 1	9.625	1627	13.2	7.70	Winton	sltst
Tirrawarra 65	9.625	5585	12.4	24.81	Cadna-Owie	sst
Tirrawarra 67	9.625	2006	13.8	9.92	Winton	sltst
Tirrawarra 68	9.625	2007	15	10.79	Winton	clst
Tirrawarra 69	9.625	3605	14.8	19.12	Winton	sltst
Wantana 2	9.625	5444	15.7	30.63	Cadna-Owie	sst/sltst

Formation Integrity Pressures (FIP) from Wells Within the Nappamerri Trough

Well	Casing Shoe	Depth (ft)	FIP (ppg)	FIP (MPa)	Formation	Lithology
Bulyeroo 1	9.625	7776	14.5	40.40	Nappamerri	sst
Burley 2	9.625	7621	16.8	45.88	Nappamerri	sltst
Kirby 2	9.625	5751	15.6	32.15	Mooga (Namur)	sst
McLeod 1	9.625	7475	16.8	45.00	Nappamerri	sltst/sst

Appendix II: Mud Weights from Wells Within the Nappamerri Trough.

Well	Depth (ft)	MW (ppg)	MW (MPa)
Bulyeroo 1	560	8.7	1.75
Bulyeroo 1	825	8.8	2.60
Bulyeroo 1	1810	8.6	5.58
Bulyeroo 1	3725	8.7	11.61
Bulyeroo 1	4310	8.9	13.74
Bulyeroo 1	5315	8.8	16.76
Bulyeroo 1	6075	8.8	19.16
Bulyeroo 1	7415	8.9	23.65
Bulyeroo 1	7680	8.8	24.22
Bulyeroo 1	7825	8.9	24.95
Bulyeroo 1	8045	9	25.94
Bulyeroo 1	8365	9.4	28.17
Bulyeroo 1	8950	10.1	32.39
Bulyeroo 1	9170	10.1	33.19
Bulyeroo 1	9865	12.9	45.60
Bulyeroo 1	9935	12.9	45.92
Bulyeroo 1	10070	13	46.91
Bulyeroo 1	10140	12.9	46.87
Bulyeroo 1	10320	13.3	49.18
Bulyeroo 1	10470	14	52.52
Bulyeroo 1	10625	14.1	53.68
Bulyeroo 1	10755	14.3	55.11
Bulyeroo 1	10885	14.8	57.72
Bulyeroo 1	10940	14.6	57.23
Bulyeroo 1	11045	14.4	56.99
Bulyeroo 1	11180	14.4	57.69
Bulyeroo 1	11305	14.5	58.74
Bulyeroo 1	11480	14.4	59.23
Burley 1	8700	9.3	28.99
Burley 1	8734	10.2	31.92
Burley 1	10033	10.8	38.83
Burley 1	10149	13.6	49.46
Burley 1	10238	14.6	53.56
Burley 1	10285	14.7	54.17
Burley 1	10358	14.6	54.19
Burley 1	10405	14.6	54.43
Burley 1	10680	14.5	55.49
Burley 1	10913	14.6	57.09
Burley 1	11226	14.7	59.13
Burley 1	11625	14.7	61.23
Burley 1	11780	14.6	61.63

Well	Depth (ft)	MW (ppg)	MW (MPa)
Burley 2	4450	9.2	14.67
Burley 2	4640	9.1	15.13
Burley 2	5040	9.1	16.43
Burley 2	5180	9.3	17.26
Burley 2	5600	9.4	18.86
Burley 2	6010	9.5	20.46
Burley 2	6460	9.5	21.99
Burley 2	6725	9.5	22.89
Burley 2	7200	9.3	23.99
Burley 2	7310	9.2	24.10
Burley 2	7745	9.3	25.81
Burley 2	7905	9.4	26.63
Burley 2	8185	9.4	27.57
Burley 2	8670	9.4	29.20
Burley 2	8860	9.4	29.84
Burley 2	9070	9.4	30.55
Burley 2	9550	13	44.48
Burley 2	9725	13	45.30
Burley 2	10060	13.5	48.66
Burley 2	10295	13.8	50.91
Burley 2	10360	13.2	49.00
Burley 2	10480	12.6	47.31
Burley 2	10555	12.7	48.03
Burley 2	10760	12.7	48.96
Burley 2	10895	13.4	52.31
Burley 2	11005	13.1	51.66
Burley 2	11170	13	52.03
Burley 2	11445	13	53.31
Burley 2	11870	12.9	54.87
Kirby 1	852	8.8	2.69
Kirby 1	4969	9.3	16.56
Kirby 1	5470	10.1	19.80
Kirby 1	6456	10.1	23.36
Kirby 1	6600	9.95	23.53
Kirby 1	7681	9.9	27.25
Kirby 1	8514	10.6	32.34
Kirby 1	8980	10.5	33.79
Kirby 1	9341	13	43.51
Kirby 1	9757	15	52.44
Kirby 1	10395	13.1	48.79
Kirby 1	10718	14.8	56.84
Kirby 1	11525	14.1	58.23
Kirby 1	12180	14.2	61.97
Kirby 1	12598	15.4	69.52

Well	Depth (ft)	MW (ppg)	MW (MPa)
Kirby 2	430	8.7	1.34
Kirby 2	610	8.6	1.88
Kirby 2	1035	8.5	3.15
Kirby 2	2485	8.9	7.92
Kirby 2	4415	9.1	14.40
Kirby 2	5355	9.2	17.65
Kirby 2	5525	9.2	18.21
Kirby 2	5765	9.1	18.80
Kirby 2	6120	9.1	19.96
Kirby 2	6460	9.2	21.30
Kirby 2	6460	9.4	21.76
Kirby 2	6760	9.2	22.28
Kirby 2	6760	9.4	22.77
Kirby 2	6900	9.2	22.75
Kirby 2	6900	9.4	23.24
Kirby 2	7190	9.2	23.70
Kirby 2	7660	9.2	25.25
Kirby 2	7660	9.4	25.80
Kirby 2	7800	9.2	25.71
Kirby 2	7800	9.4	26.27
Kirby 2	7960	9.6	27.38
Kirby 2	7960	9.8	27.95
Kirby 2	8100	9.6	27.86
Kirby 2	8100	9.8	28.44
Kirby 2	8260	9.6	28.41
Kirby 2	8400	9.6	28.89
Kirby 2	8400	9.8	29.50
Kirby 2	8560	9.8	30.06
Kirby 2	8670	9.8	30.44
Kirby 2	8760	9.8	30.76
Kirby 2	8920	9.8	31.32
Kirby 2	9010	9.8	31.64
Kirby 2	9110	9.8	31.99
Kirby 2	9305	9.8	32.67
McLeod 1	5000	9.6	17.20
McLeod 1	6000	9.6	20.64
McLeod 1	7000	9.5	23.83
McLeod 1	7350	9.5	25.02
McLeod 1	7450	9.1	24.29
McLeod 1	8000	9.1	26.09
McLeod 1	8500	9.1	27.72
McLeod 1	8700	9.2	28.68
McLeod 1	8800	9.3	29.32
McLeod 1	8900	9.5	30.30
McLeod 1	9000	9.9	31.93
McLeod 1	9100	9.9	32.28
McLeod 1	9200	9.9	32.64
McLeod 1	9300	10	33.32
McLeod 1	9400	10.5	35.37
McLeod 1	9500	11.2	38.12
McLeod 1	9600	12.2	41.97
McLeod 1	9700	13	45.18
McLeod 1	9800	13.1	46.00
McLeod 1	9900	13.2	46.82
McLeod 1	10000	13.1	46.94
McLeod 1	10500	13.2	49.66
McLeod 1	11000	13.1	51.63
McLeod 1	11500	13.1	53.98
McLeod 1	12000	13.1	56.33
McLeod 1	12500	13.2	59.12