The Mangahewa Gas Field

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Abstract

The Mangahewa Gas Programme was presented at the 1998 Petroleum Conference at the time of the long term testing of Mangahewa-2. Since then the discovery has been appraised by long term testing, 3D seismic survey and further drilling. This paper outlines the results of this appraisal effort.

The Mangahewa Gas Field was discovered by the Mangahewa-2 well in 1997. This crestal exploratory well penetrated a series of fluvial reservoir sandstones in the 1000 m thick Eocene Mangahewa Formation at depths below 3300 m subsea. The sandstones were approximately 20 m thick with average porosities ranging from 8 to 11% and many zones having permeabilities in the sub-milliDarcy range. Three sandstone intervals were selected for hydraulical fracturing. Although two produced gas at sub-commercial rates, one sandstone reservoir, MA72, flowed gas at a rate of 17.5 mmscfd with a flowing pressure of 4450 psi on a 24/64” choke (facilities constrained).

The well was put on a long-term production test for 7 months and produced a total of 2.7 bcf of gas and 38,000 barrels of condensate.

The Mangahewa Field is located on a regional inversion anticline. At the time of Mangahewa-2 testing this was believed to possibly extend into the offshore to the north of the well penetration. A 3D seismic survey of 211 sq km was conducted in late 1997 to early 1998 to more accurately define the structure and facilitate the appraisal drilling effort. Interpretation of the survey indicated that the onshore gas bearing structure was less extensive than inferred from sparse 2D seismic data and that it was separated from a second crest in the offshore area. As a consequence, plans to drill a deviated well from the coast into the offshore part of the structure, called Pohokura, were cancelled. The latter structure thus became a separate exploration play, independent of the Mangahewa structure. An offshore exploration well on this structure (which is still called Pohokura) will be drilled by the PEP 38459 joint venture early in 2000.

The first appraisal well, Ohanga-2, was drilled in late 1998 to test the lateral extent of the productive MA72 reservoir in a structural position close to lowest known gas in Mangahewa-2. It penetrated the Mangahewa reservoir section on prognosis, 4.2 km along strike to the southwest of Mangahewa-2. It found low gas saturations in reservoir sands correlative to those penetrated in Mangahewa-2. Two reservoirs including the MA72 were tested, producing minor quantities of water at very low rates. This confirmed the petrophysical evaluation that the reservoirs were penetrated at or near individual gas water contacts. As a result, further seismic acquisition and appraisal drilling proved unnecessary and it was determined to be most economic to apply for a mining permit with a view to early development. The mining permit application is currently being prepared and its submission plus relinquishment of acreage outside the mining permit area will be completed within the time requirements of the existing permit.

The Mangahewa Gas Field has estimated Proven plus Probable reserves of 101 bcf contained entirely within the MA72 reservoir.

Introduction

The Mangahewa Gas Field was discovered by the Mangahewa-2 well in 1997. The Mangahewa Gas Programme was presented at the 1998 Petroleum Conference and focussed on the successful drilling, hydraulic fracturing, and testing of this well. Since then the discovery has been appraised by long term testing, a 3D seismic survey and the drilling of the Ohanga-2 well.

The Mangahewa-2 site was chosen because it lies above the crest of the in situ Mangahewa Structure to minimise the risk of geological failure and to penetrate sandstones with potential maximum gas saturations. This exploratory well penetrated a series of fluvial reservoir sandstones in the 1000 m thick Eocene Mangahewa Formations at depths below 3300 m subsea. The sandstones were approximately 20 m thick with average porosities ranging from 8 to 11% and many zones having permeabilities in the sub-milliDarcy range. Three sandstone intervals were selected for hydraulic fracturing. Although two produced gas at sub-commercial rates, one sandstone reservoir, MA72, flowed gas at a rate of 17.5 mmscfd with a flowing pressure of 4450 psi on a 24/64" choke (facilities constrained).

The well was put on a long-term production test for 7 months and produced a total of 2.7 bcf of gas and 38000 barrels of condensate.

This paper will discuss the results of the now completed appraisal of the Mangahewa Field and will include the results of the long-term testing of the Mangahewa-2 well, the 3D seismic survey and the drilling and testing of the Ohanga-2 well.

Mangahewa-2

Over 1997 and 1998 a series of long-term production tests were performed on Mangahewa-2 to determine GIIP, reserves and deliverability trends. The tests consisted of an initial pressure build-up test, a multi-rate flow test, and a final pressure build-up test.

Initial pressure build-up analysis

The best quality well test interpretation in Mangahewa-2 was carried out on the post stimulation MA72 interval covering 18 August to 12 September flow and 12 to 29 September 1997 build-up and was conducted using data from high precision Panex gauges. The low (@600 psi) maximum drawdown, recorded with bottom hole pressure gauges, combined with the low CO_2 levels, indicated that only the MA72 interval was contributing to flow, although the MA83 interval was also open. This is because of the considerably higher drawdown (>2500 psi) required to get significant flow rates from The MA83 interval which is limited in extent (approximately 0.5 bscf based on material balance analysis).

Figure 1 gives a summary of the flow rates and pressures recorded from 2 to 12 September 1997.

The log-log buildup analysis plot is shown in Figure 2 and shows the wellbore storage (slope of 1), frac bi-linear flow regime (1/4 slope) and a pseudo-radial flow regime (zero slope on derivative) followed by complex boundary behaviour. The plot also shows the analytical fit to the observed data.

This analysis of the MA72 interval gave a Kh of 267 mDft, a fracture half-length of 91 ft (c.f. 96-120 ft from the stimulation contractor's reports), and an initial pressure of 6440 psia at the gauge depth of 3445.38 mAHBKB (3314.1 mTVSS).

The flow thickness used was that of the MA72 interval only i.e. 18 m (59 ft). The build-up radius of investigation was in excess of 3300 ft but the level of depletion during the flow test, which produced 0.22 bcf, was unquantifiable due to the lack of a reliable initial pressure.

Multi-rate flow analysis

A three step multi-rate test was performed from 26 June to 27 July 1998. The well was run at flowrates of 6.3, 10.4 and about 15.7 mmscfd over this period and the data obtained

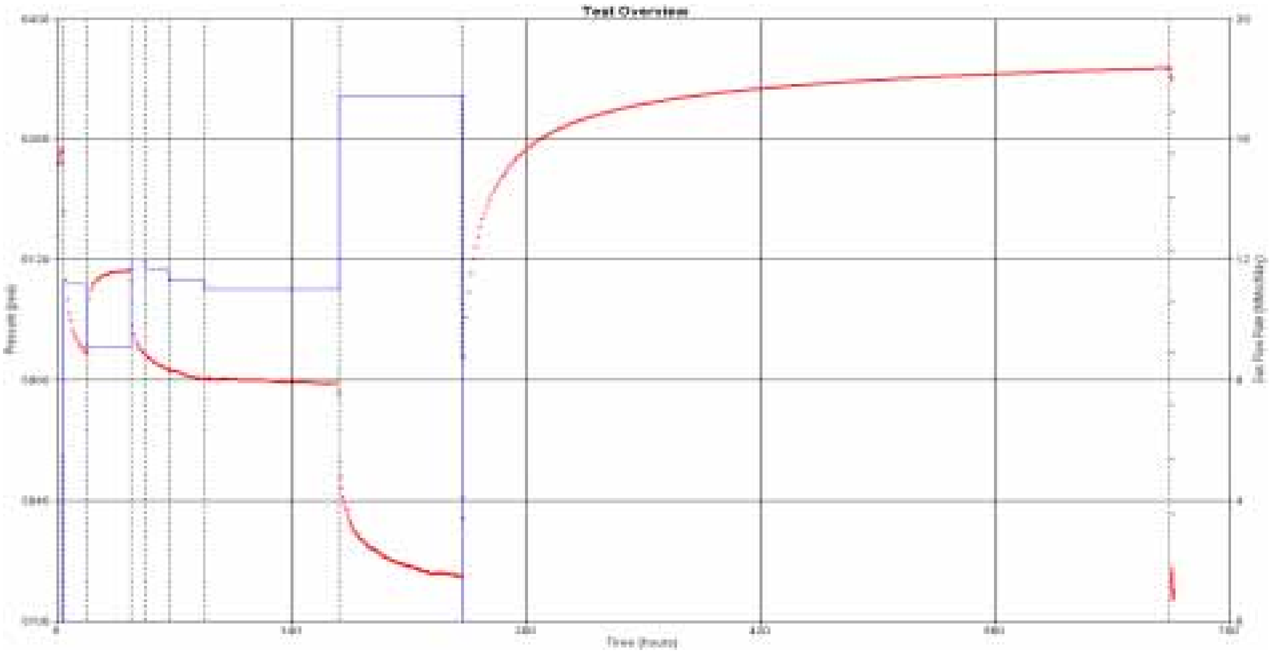

Figure 1: Mangahewa-2 — Initial buildup - pressure and flow rate vs time.

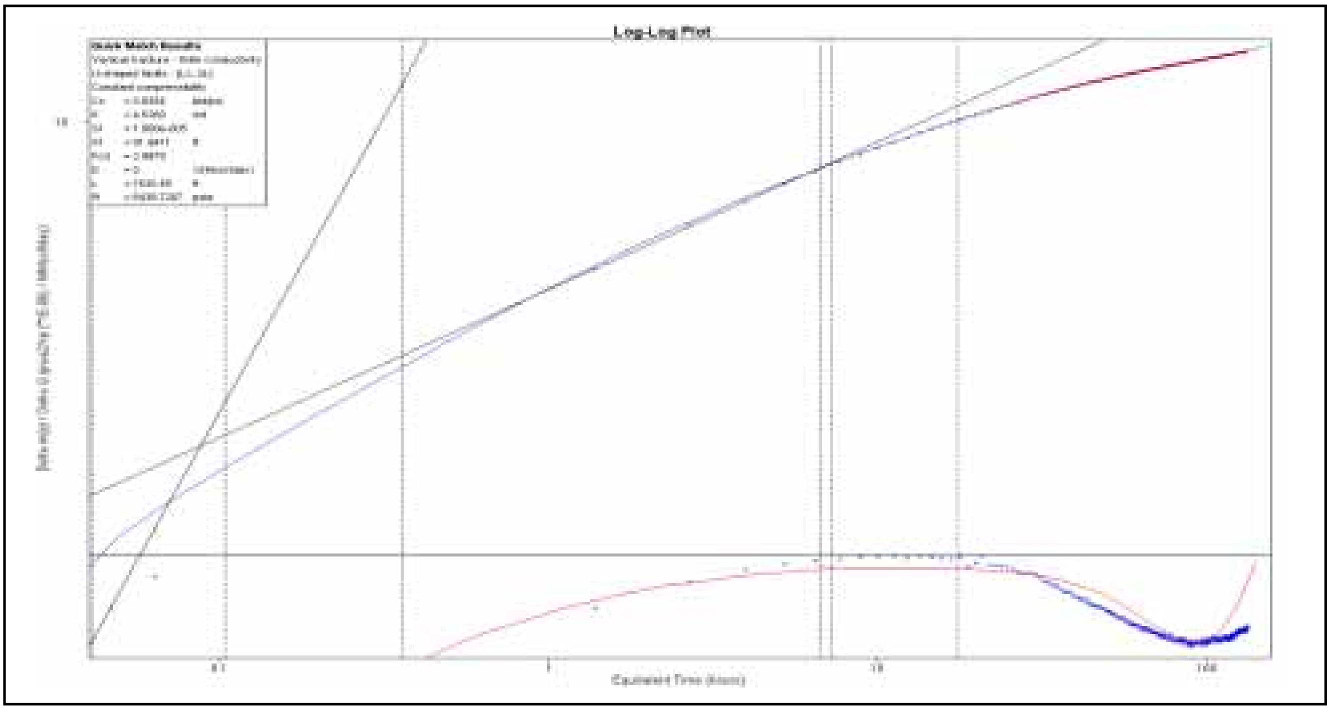

Figure 2: Mangahewa-2 — Initial buildup - log-log analysis plot.

was combined with the previous flow performance of the Mangahewa-2 well. This complete rate history of the well was entered into the welltest analysis software and a number of models tested to find a best match by trial and error. The flow periods for the multi-rate tests were also analysed individually and all the results were then combined into a single interpretation.

A reasonable match was been obtained using the following parameters:

Wellbore storage model	Classic wellbore storage
Flow model	Vertical Fracture - finite conductivity
Boundary model	U-shaped faults -central well position (L:L:L) -all 3 boundaries closed
Kh	502 mD.ft
Cs	3 bbl/psi
Sf	0.02
Xf	92 ft
Fcd	3
D	1e-6 1/mscfd

The multi-rate test was also used to develop tubing performance curves to be used for future development plans. Figure 3 shows the tubing performance match for the multirate test. The estimated AOF was 83 mmscfd.

Second pressure build-up analysis

A second pressure build-up was carried out between 1 August and 20 November after the multi-rate test had been completed.

It can be seen from the log-log and semi-log plots (Figures 4 and 5) that the measured data does not match the analytical fit. This can be explained by after-flow effects caused by cross-flow between the zones. The early time data needs adjusting to account for this after-flow, however this is a difficult procedure and has not been done. The radial flow period was identified from the plots and was used to calculate permeability thickness and skin. A simplistic radial model (infinitely acting) was used for this initial analysis which gave a kh of 454 mDft and a skin of -3.75. This was an increase in kh but a decrease in skin from previous analyses but is consistent with the expected rock properties for this zone based on core data. The well was also analysed using a vertical fracture - finite conductivity model with the same rock properties and a fracture with a 92 ft half length and conductivity of 3 (same as previous analyses). Although the late radial flow straight line was a bit noisy there were no obvious boundary effects. Although no boundary effects were seen it was impossible to obtain an overall pressure match if boundaries are not assumed. In order to quantify the nature of the boundaries, analytical simulation was undertaken as discussed below.

Simulation

There is a feature in the welltest analysis software that allows simulation of a particular rate schedule. This simulation predicts the pressure response of a reservoir layer based on the model assumed. Different models can be entered for wellbore storage, flow and boundary conditions to obtain the optimal match. This was done for Mangahewa-2 by trial and error, using the whole pressure history of the well. In order to obtain a good match, some sort of boundary had to be assumed, otherwise the reservoir pressure is overestimated. The best match was obtained by using a U-shaped fault system. Two sensitivities were considered to estimate the

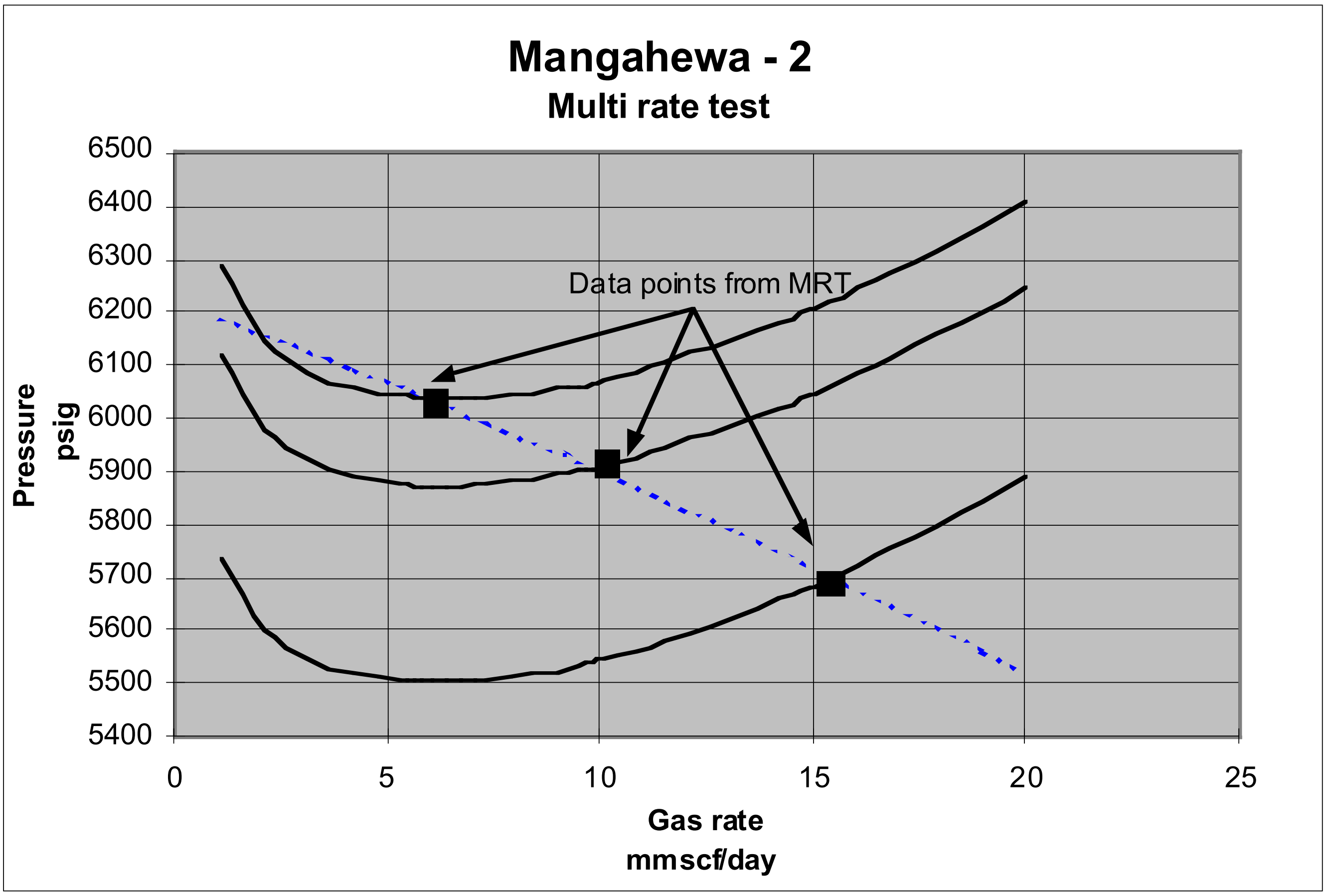

Figure 3: Multi rate test data match with tubing performance.

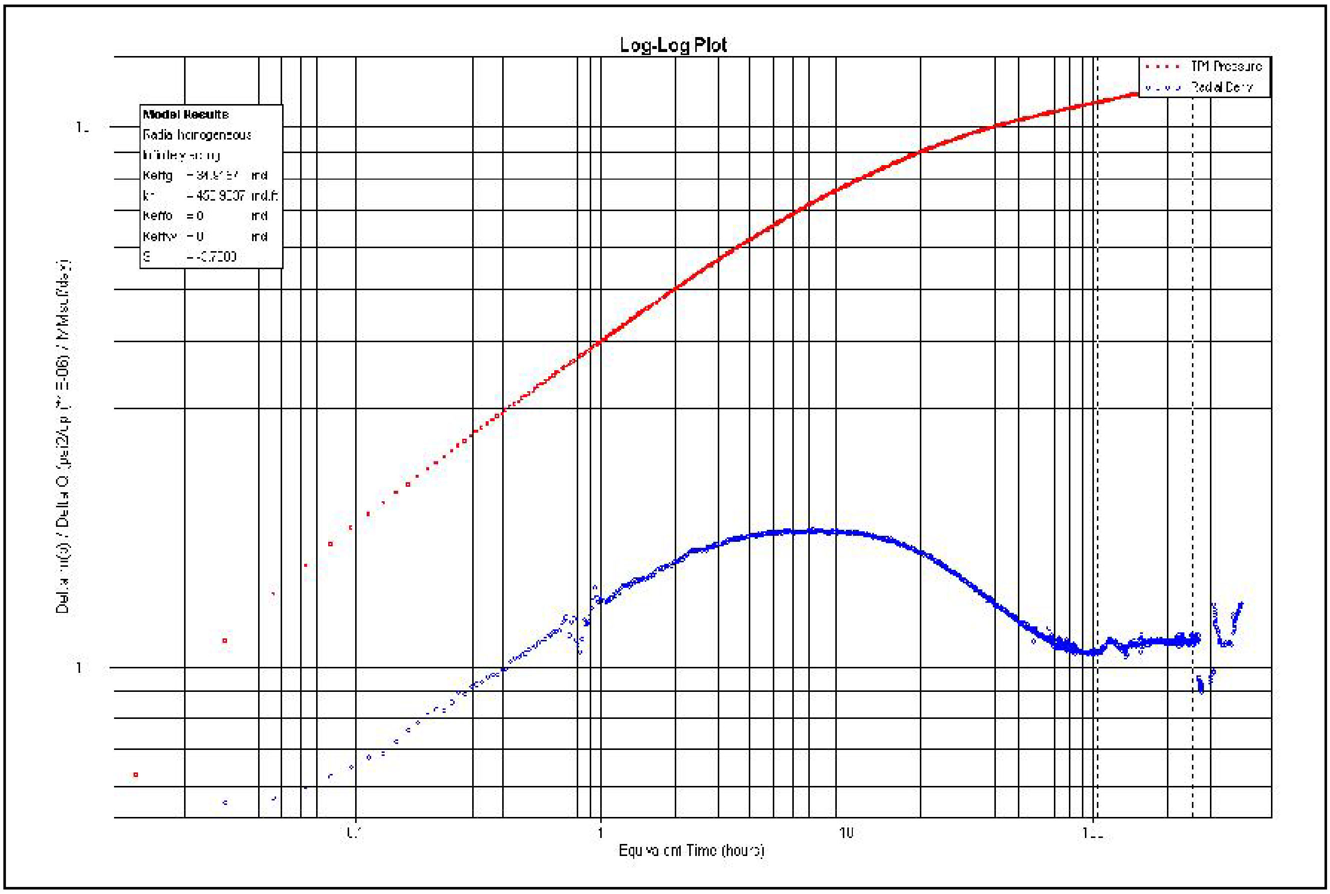

Figure 4: Log-Log plot for Mangahewa-2.

Figure 5: Radial flow for Mangahewa-2.

distance of the boundaries. If the total perforated interval was considered as contributing to flow (59 ft or 18 m) then boundaries were inferred at a distance of 3800 ft (1158 m). If a smaller interval was contributing with a thickness of 13 ft (4 m) then the boundaries would be at 8200 ft (2499 m). This essentially gave the minimum and maximum range of boundary distance. From seismic data, there was a possible fault seen approximately 1600 m from Mangahewa-2, but no “U-shaped” system. It is also possible that the underlying aquifer is acting as some sort of pressure boundary or there is degradation in reservoir properties (or pinchout) some distance from the well.

Figure 6 shows the overall rate and pressure history for Mangahewa-2 (the clock started ticking on 7 June 1997) with the simulated pressure response overlain. The simulation used a permeability of 6.4 mD a skin of -3.6 and thickness of 59 ft with a U-shaped fault system at a distance of 3800 ft. As can be seen from the plot, an excellent match was achieved.

3D seismic study

In late 1997 to early 1998 a 3D seismic survey was conducted to more accurately define the Mangahewa structure and facilitate the appraisal drilling effort. The survey covered 211 sq km with a 60 m x 60 m grid spacing. Mangahewa-1 & -2, Manganui-1 & -2, and McKee-1 were located within the 3D and Ohanga-2 was located 1 km to the east. At depths of 3000-4000 m the frequency content is between 60-70 Hz and although the seismic is noisy it provides excellent imaging of the Kapuni Group.

Various vintages of pre-1989 onshore lines augment the 3D dataset over the Mangahewa structure. However these 2D lines suffer from numerous misties, poor resolution, and raypath distortion in the vicinity of the McKee and Ohanga thrusts. Misties in the mapping were minimised by first determining appropriate bulk shifts to each line. The bulk shifts were calibrated to the P95- vintage, a marine seismic dataset. The Tikorangi Limestone is a characteristic seismic event onshore and was used to ensure both TWT and phase consistency when applying bulk shifts. Misties are numerous and variable and residual misties at both top Tikorangi and MA99 are all less than 20 msec.

Interpretation of the 3D survey indicated that the onshore gas bearing structure was less extensive than inferred originally from the sparse 2D seismic data and that it was separated from a second crest in the offshore area. This saddle splits what was believed to be one larger structure in two smaller structures named the Mangahewa and Pohokura structures. The Mangahewa 3D facilitated this discovery through a combination of constant statics and close spaced spatial sampling which clearly defined the saddle and its structural context. Figure 7 shows a depth structure map generated from the 3D survey data.

The Mangahewa Formation has been interpreted as a stratigraphically complex interdigitation of fluvial/estuarine and marine sequences. With Mangahewa-2 as the primary well tie a number of event have been interpreted on the Mangahewa 3D. The interval between MA99 and MA88 is the McKee Formation, deposited under coastal conditions and capped by the marine Turi shale. The interval thins

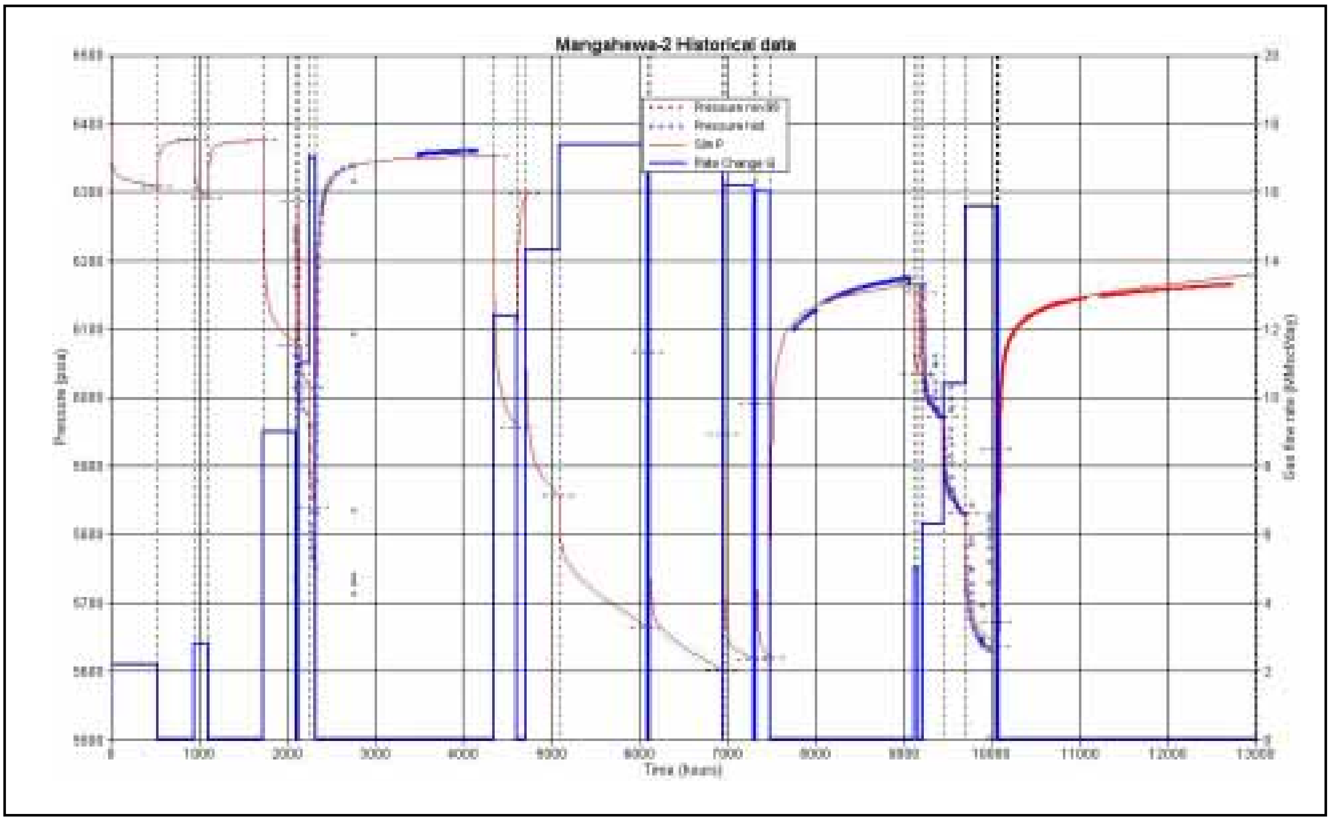

Figure 6: Match of total Mangahewa-2 pressure response.

dramatically to the north and west off the flanks of the Mangahewa structure. Coal seams at the base of the McKee are clearly visible on seismic and their extent can be mapped with confidence.

MA83 to MA50 comprise the upper Mangahewa Formation, a sequence coal bearing and deposited in a lower coastal plain environment at Mangahewa-2. The extent of this coal is as dramatically delineated as the MA88 but can still be seen to diminish in amplitude in a northwesterly direction. Amplitude is also seen to drop along the Lepperton Fault (where steep dips make the seismic discontinuous) and north of Mangahewa-1 along the path of a channel incision.

The MA71-MA72 interval has had a significant change in interpretation post Mangahewa 3D. The higher frequency content and improved spatial sampling of the Mangahewa 3D has improved the vertical resolution and interpretation of these events to the extent that the interval can be mapped with confidence over the entire 3D volume. This interpretation concurs with the current log interpretation that the interval is marine sand and demonstrates the high degree of interdigitation between terrestrial and fluvial sediments in the upper Mangahewa. The MA71-MA72 interval is thickest to the east and south-east and thins to the north-west.

Ohanga-2 appraisal well

Ohanga-2 was drilled in late 1998 with the main purpose of testing the lateral extent of the productive MA72 reservoir. The well was placed in a structural position close to lowest known gas in Mangahewa-2. It was also intended to evaluate the other reservoirs in the Mangahewa Formation, acquire a full suite of log and core data for better evaluation of Mangahewa Formation reserves and fulfil the first year commitment of PPL 38705 Appraisal Extension work programme commitment. Prior to drilling, the risk assessment for Ohanga-2 had estimated the chance of encountering producible hydrocarbons as 58% with the highest risk factor being commercial producibilty (high enough gas saturation to be commercial) followed closely by reservoir quality. The P50 (proven plus probable) pre drill estimate of gas volumes assumed an incremental GIIP of 24 bscf for the MA72 sand with 49 bscf of GIIP for other zones within the well. This gave a total reserve of 51 bscf associated with the P50 outcome. The Proven case assumed no incremental gas for zone MA72 and a small reserve associated with other zones (11 bscf). The upside case (proven plus probable plus possible) assumed a total an incremental reserve of 149 bscf.

The well was drilled to c. 70 m above MA0 (Omata Shale) and numerous Mangahewa Formation sandstone reservoirs with shows were encountered, although most intervals were interpreted to be close to residual conditions. The original well planning allowed for up to three zones to be tested. However, due to the disappointing well results, it was decided to test only two zones. All the predicted zones were encountered close to prognosis. The well showed very good correlation with the Mangahewa-2 well (see Figure 8).

It was decided to test the MA28 and MA72 zones to satisfy the pre-drill testing requirements which had been specified as follows:

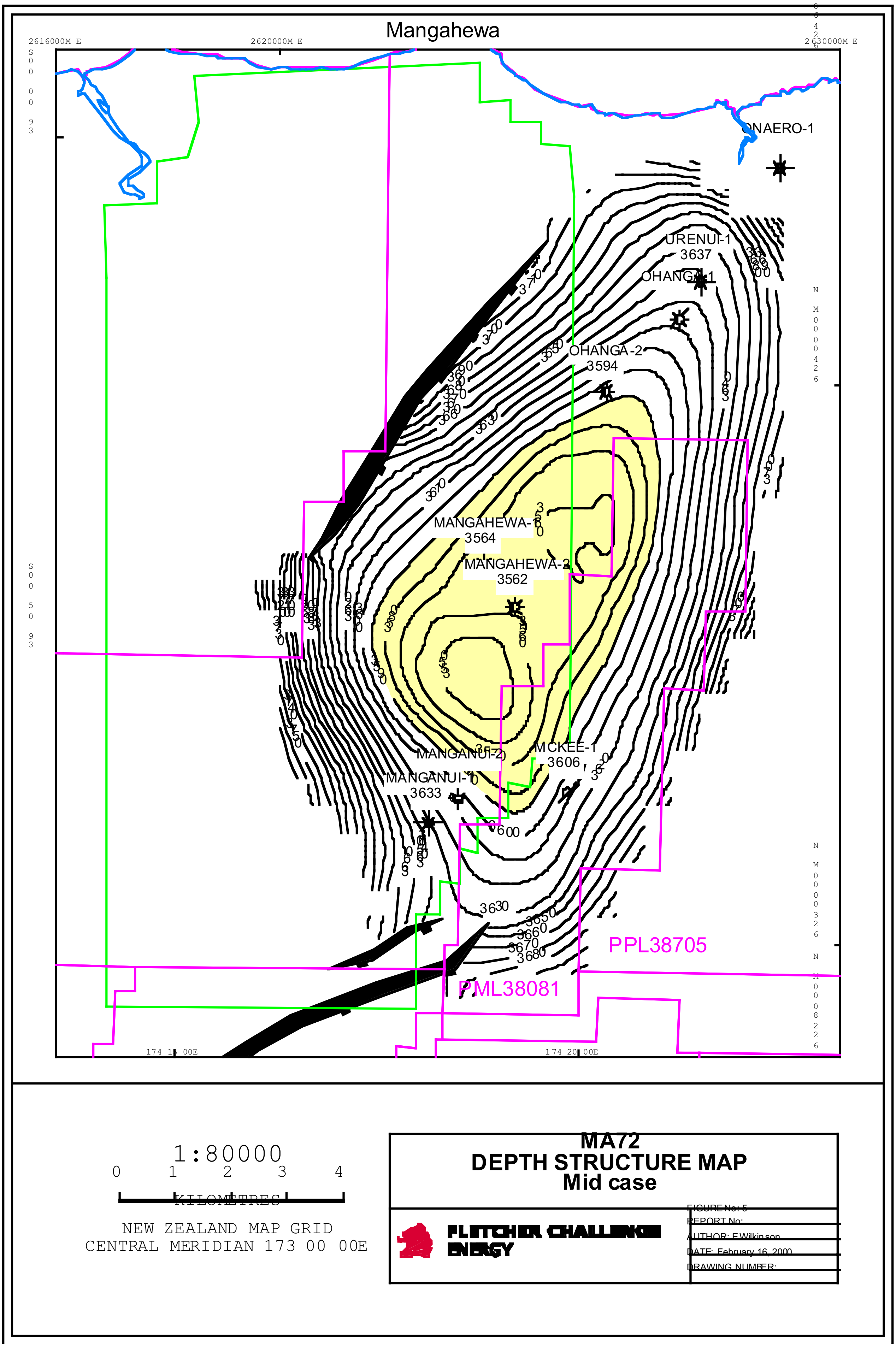

Figure 7: MA72 depth structure map — mid case.

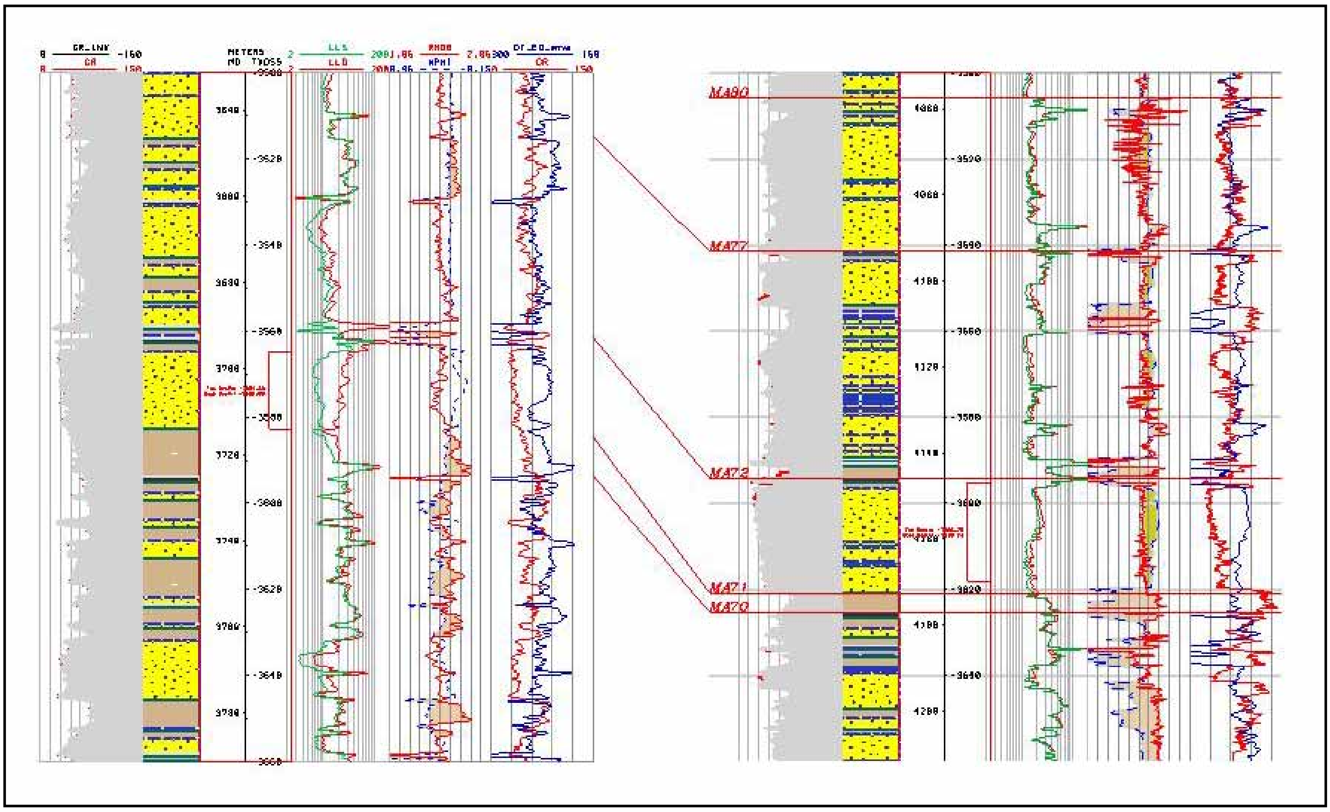

Figure 8: Correlation between Mangahewa-2 and Ohanga-2.

(a) To test lower productivity reservoir in order to be able to determine the total productive interval of the Mangahewa Formation. This would establish commercially viable productive reservoirs beyond the MA72 zone at Mangahewa-2. It would be likely that these lower productivity zones would require hydraulic fracture stimulation to achieve commerciability.

(b) To establish the presence, reservoir quality and gas content of the MA72 zone equivalent reservoir.

The two zones selected to be tested were the MA28 zone which had the highest estimated hydrocarbon thickness (but with low estimated permeability) and the MA72 interval, which had been tested at Mangahewa-2.

Following difficulties with the perforating guns the MA28 reservoir interval was eventually perforated significantly overbalanced. Test flows were small and a ball-out treatment yielded only a minor improvement. Limited water but no gas was produced before the zone was permanently abandoned.

The MA72 interval produced no hydrocarbons, and only 15 barrels of water per day, despite swabbing. A core had been taken over this zone and showed no evidence of fluorescence (see Figures 9 and 10).

The absence of produced hydrocarbons confirmed petrophysical evaluation that the reservoirs were penetrated at or near individual gas water contacts. This restricted the size of the Mangahewa Field and further seismic acquisition and appraisal drilling became unnecessary. It became most economic to apply for a mining permit with a view to early development.

Reserves

Material balance estimate of reserves

Whether material balance can be applied to a hydrocarbon accumulation as a whole depends upon how rapidly the pressure disturbance is equilibrated in the reservoir so that it may be treated as zero dimensional. This, in turn, is dependent on the diffusivity constant which, for a gas reservoir (even if it is tight), is large enough for material balance to be used as the foremost technique to history match and predict reservoir performance. The two principal methods of material balance are Havlenah & Odeh and the p/Z interpretation techniques. Although material balance is supposed to be one of the simplest subjects in the whole of reservoir engineering there are great subtleties attached to its application which, if unappreciated, can lead into serious errors in assessing the drive mechanism (waterdrive or volumetric). The use of the p/Z plot versus cumulative production can lead to overestimation of the GIIP if there is an active waterdrive.

Pressure and production data have been plotted using the two methods to derive an estimate of GIIP for the Mangahewa MA72 zone. It should be noted however, that with less than 5% of the estimated GIIP produced to date it is impossible to determine whether or not there is an active waterdrive mechanism.

The two build-up analyses were used to estimate GIIP values based on p/Z plots. From the plots (Figures 11 and 12) the

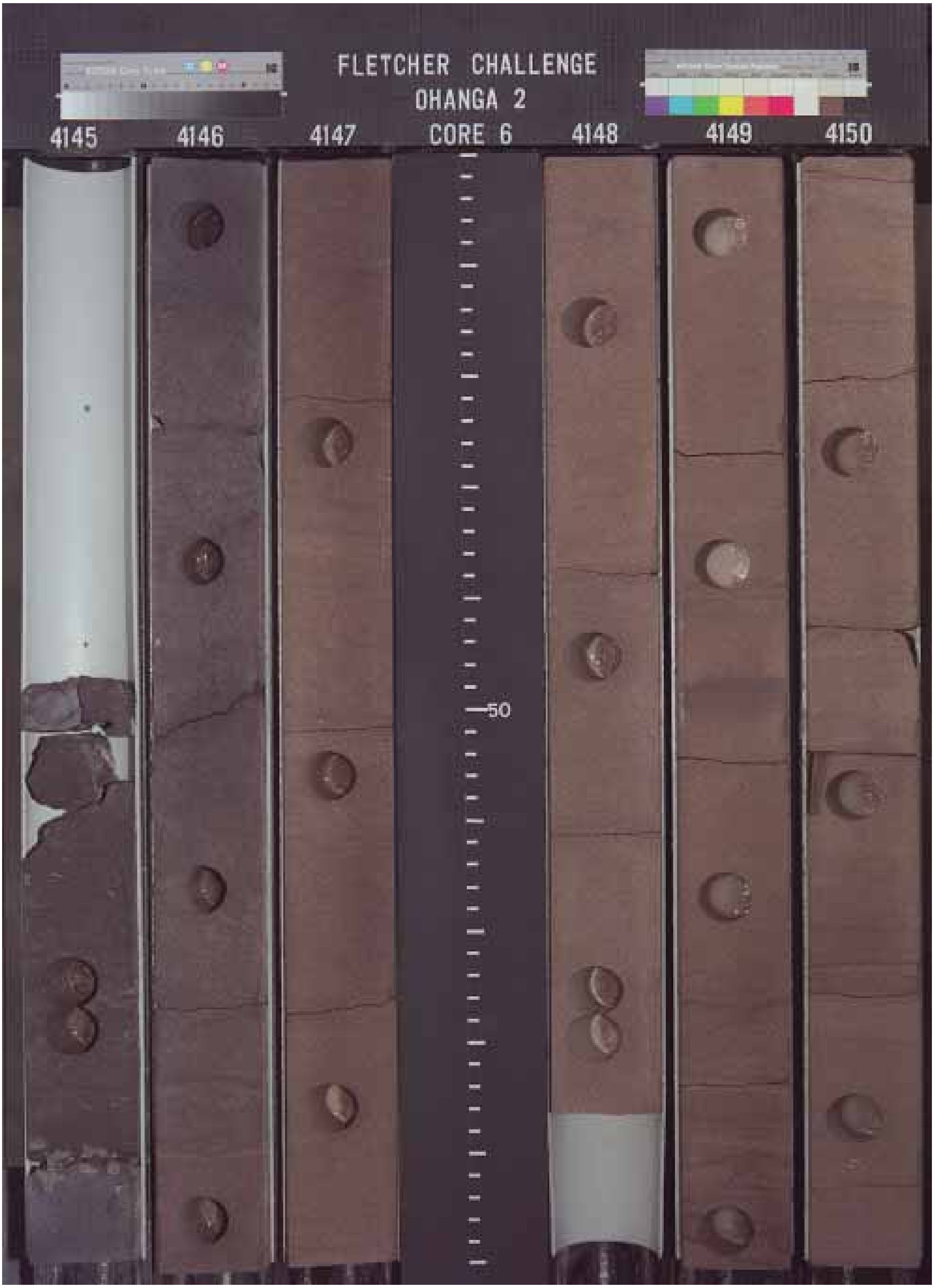

Figure 9: Core photograph from top of MA72 interval in Ohanga-2 (normal light).

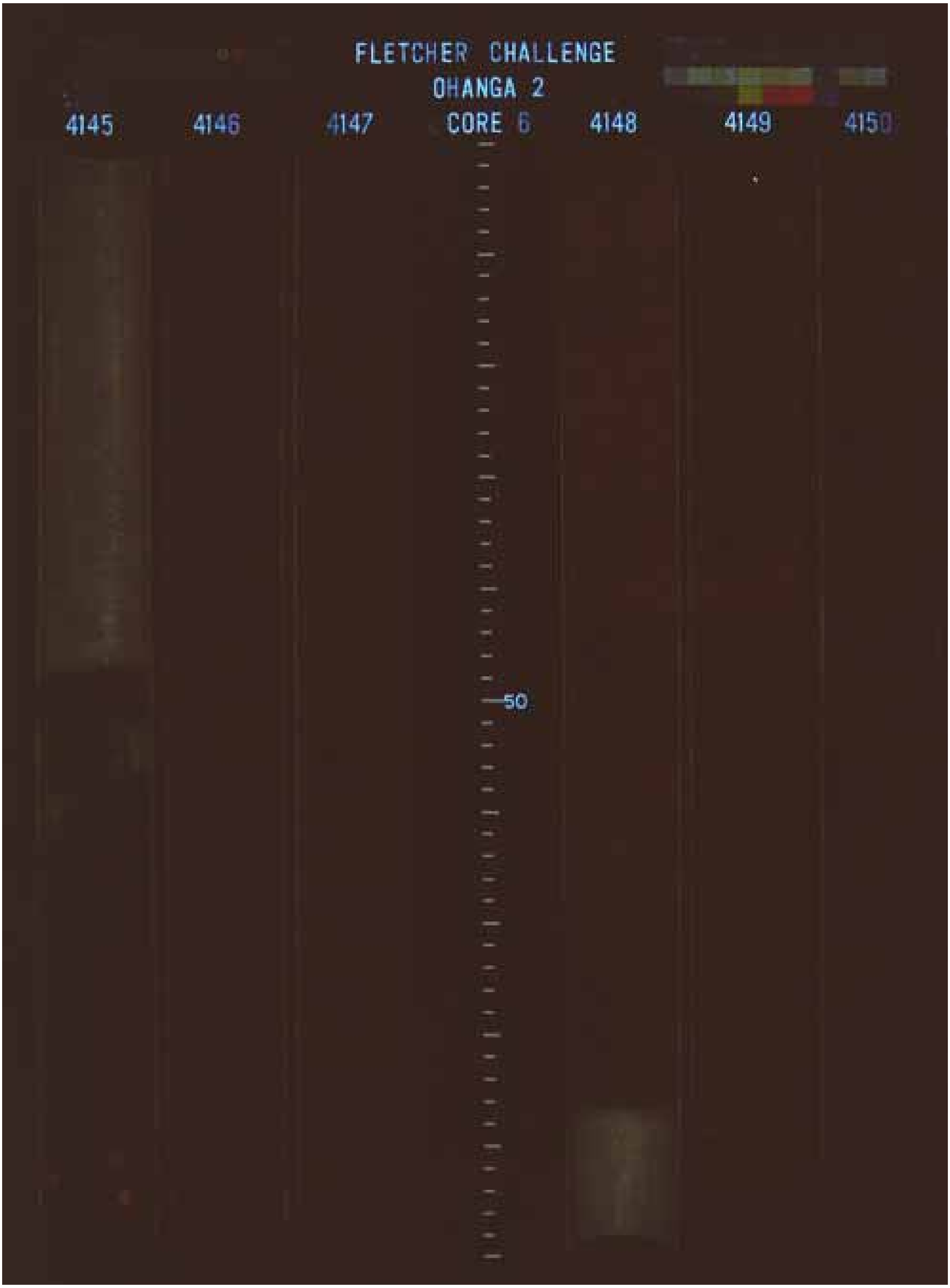

Figure 10: Core photograph from top of MA72 interval in Ohanga-2 (UV light).

GIIP looks to lie between 90 and 130 bscf. This large uncertainty is largely due to differences between maximum pressure observed during well-testing and the extrapolated pressure from build-up analysis. There will also be some uncertainty in the absolute pressure readings as different gauges were used from test to test. In addition the Havlena and Odeh method (Figure 13) yielded a GIIP of approximately 100 bscf.

Volumetric estimates of reserves

Using the 3D seismic data volumetric estimates of GIIP can be made. This number will depend upon the depth structure assumed, the gas column height, the net/gross conversion, the porosity and the hydrocarbon saturation.

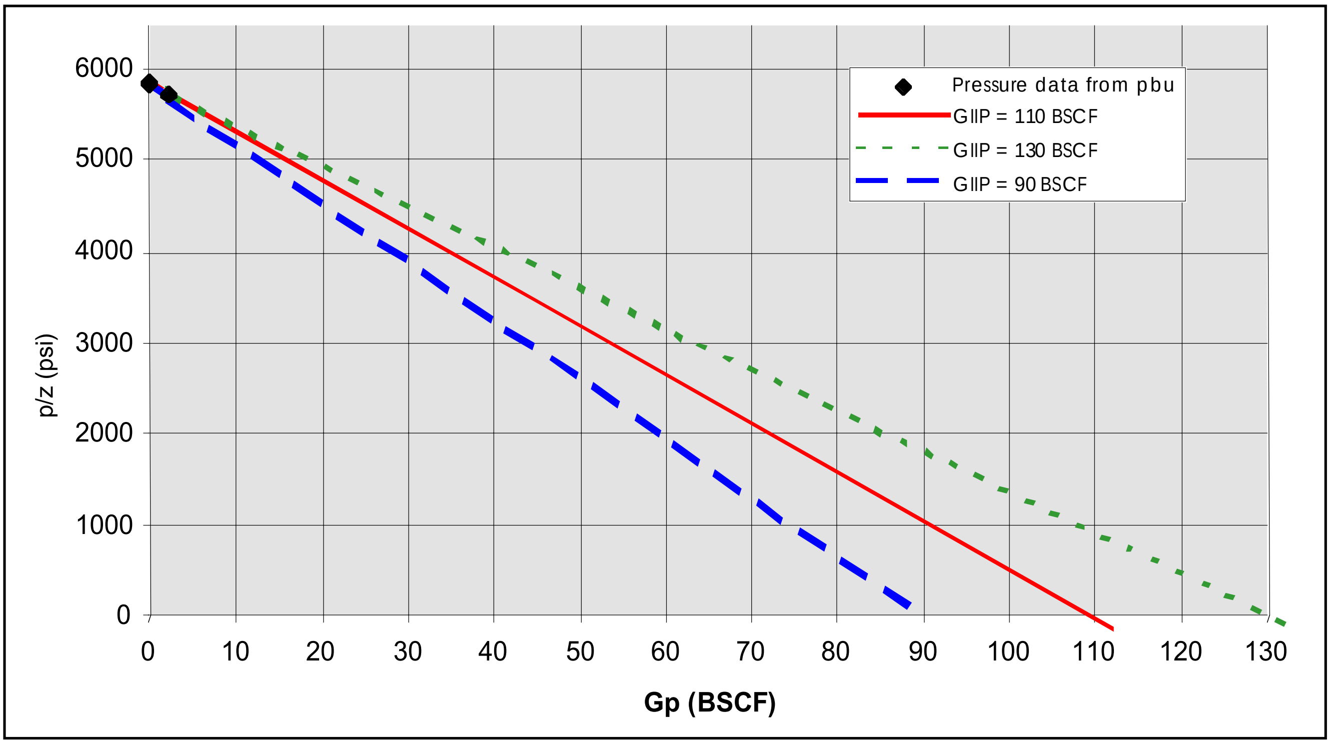

Figure 11: p/Z plot of Mangahewa-2 using pressure build-up data.

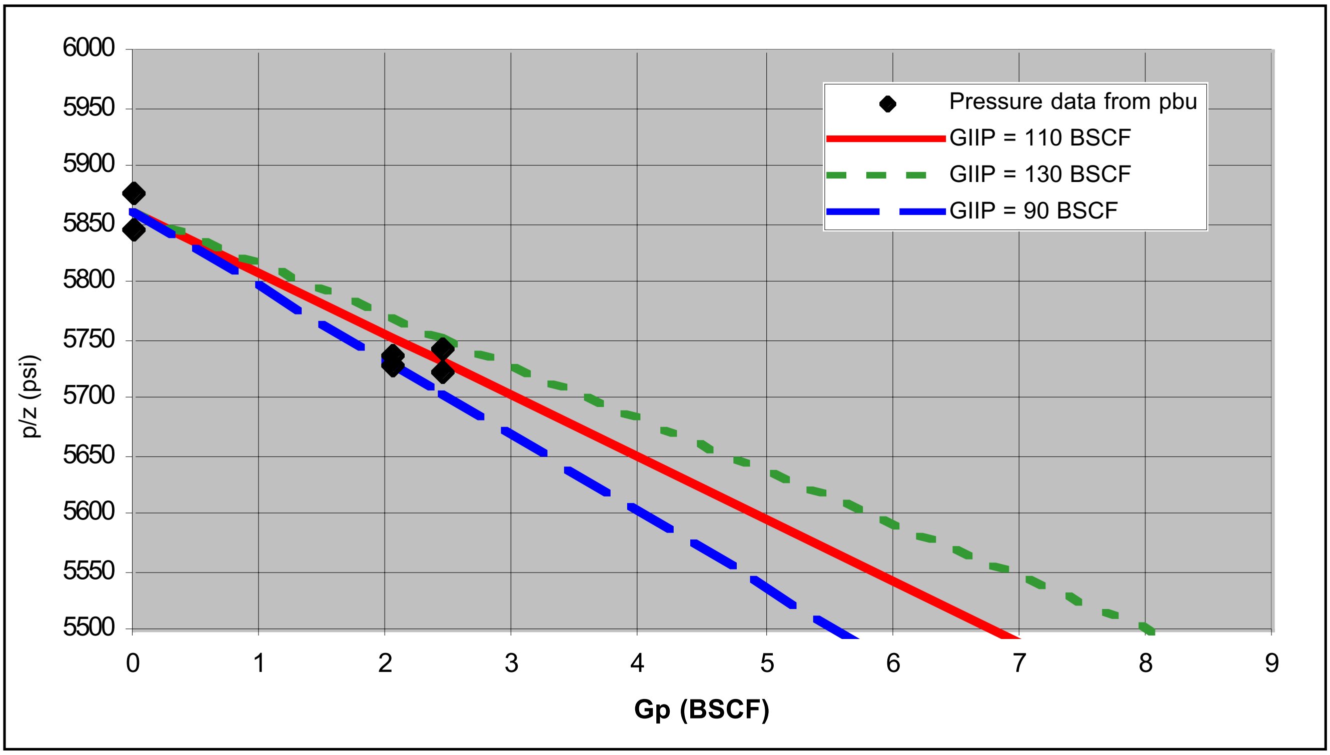

Figure 12: p/Z plot of Mangahewa-2 using pressure build-up data (close-up).

GRV

Three depths maps were derived from the same MA73 TWT map. The maps were derived by applying 3 different average velocity fields. An isopach of the MA72-MA73 interval derived from well data was added to create 3 MA72 depth maps describing the coal lying immediately above the reservoir.

FWL

Results from Ohanga-2 confirmed an expected FWL at 3590 m.

Porosity

Core data from the MA72 sand in Ohanga-2 was analysed to derive reservoir properties. A stress correction of 91% was applied to porosity (based on Mangahewa-2 SCAL data). This yielded a stress corrected average porosity of 8.3%. Average log porosity of the same interval in Mangahewa-2 yielded an average porosity of 9.3%. For the purposes of the volumetrics calculation a constant value of 9.3% porosity was assumed.

Net/gross

Permeability data from Ohanga-2 and NMR logs indicates that the reservoir exhibits permeability heterogeneity, with a higher permeability (average Ka_{core} 6.4 mD) upper member and a lower permeability (average Ka_{core} 1.6 mD) lower member. Assuming that all sand contributes to GIIP and a uniform gross interval of 30 m across the structure, an average net/gross ratio of 70% is derived from the 6 wells penetrating the MA72 interval (see Table 1). However should only the highest permeability (>2mD) part of the sand contribute then a lower N/G ratio of 43% is derived. For the purposes of the volumetrics calculation a 70% N/G is assumed.

Hydrocarbon saturation

Saturation vs height variation was modelled using both log using both log derived saturation and capillary pressure results. The average saturation calculated also tied in well with earth tide analysis carried out on Mangahewa, which gave a hydrocarbon filled porosity of approximately 5%.

Volumetric GIIP calculations

All the above data was been combined to give a total of three GIIP cases (Table 2).

Probabilistic estimate of reserves

Final reserve estimates were determined using a probabilistic assessment of modelled flow performance parameters, volumetric estimates and production to date.

In detail, they consist primarily on performance model parameters from the Mangahewa-2 build-ups in September/November 1997, May/June 1998 and August to November 1998 and its production through December 1997 up to 1 August 1998 when it was shut in. Volumetrically derived estimates using the 3D seismic dataset and petrophysical analysis and SCAL from Mangahewa-2 have also been incorporated in the analysis to derive a probabilistic distribution of reserves. They also take into account the fact that 2.72 bscf of gas and 38,000 barrels of condensate have been produced up to the end of December 1998 (average CGR is 14 bbl/mmscf).

Reserves from performance models

The reserves estimates for Mangahewa-2 below have been calculated from a range of performance models based on both boundary-volumetric approaches and on material balance.

The recovery factor used to calculate Ultimate Recovery is 70% and is discussed later in this section.

Table 3 tabulates the reserve estimates using various difference performance models, which are detailed below.

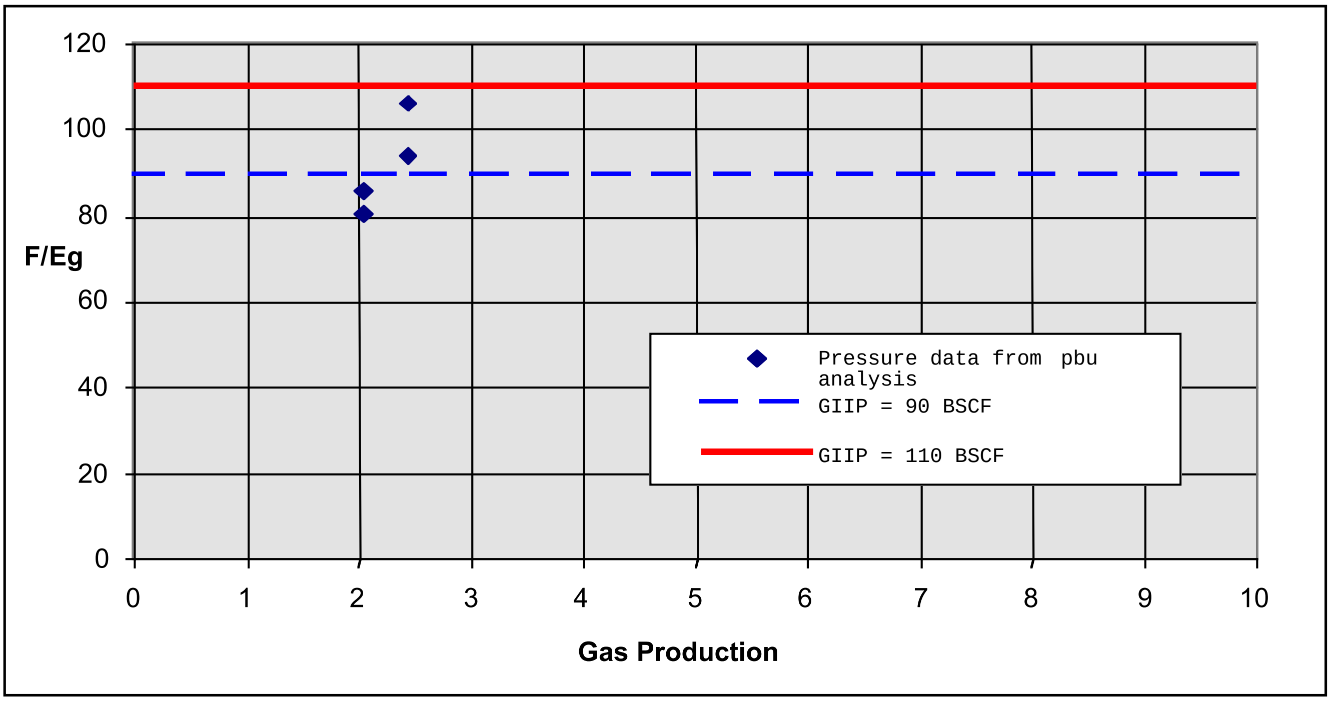

Figure 13: Havlena and Odeh plot of Mangahewa-2.

		All Clean Sand contributes (Ka > ~1mD)	Thickness of higher permeability sand	Thickness of lower permeability sand	Net (K>2md)
Wells	Thickness (m)	N/G	(K>2md)	(K<2md)	N/G
Urenui-1	21.0	70%	10	11	33%
Ohanga-2	24.0	80%	13	11	43%
Mangahewa-2	18.0	60%	8	10.0	27%
Mangahewa-1	24.5	82%	19	5.5	63%
Manganui-1	22.5	75%	15	7.5	50%
McKee-1	15.5	52%	12	3.5	40%
Total	125.5 m	70%	77 m	48.5 m	43%

Table 1: Summary of net to gross data.

Parameter	Units	P90 map	P50 map	P10 map
Closing Contour	(mSS)	3590	3590	3590
GRV	(E+6 m^3)	185	455	667
GRV*Sg	(E+6 m^3)	80	241	403
Sg	(%)	43%	53%	60%
N/G	(%)	70%	70%	70%
NRV	(E+6 m^3)	130	319	467
PHI	(%)	9.3%	9.3%	9.3%
HCPV	(%)	4.0%	4.9%	5.6%
Unit conversion	(m^3-ft^3)	35.31	35.31	35.31
GEF	(scf/rcf)	295	295	295
GIIP	(bcf)	54	163	273
Recovery Factor	(%)	70%	70%	70%
Reserves	(bcf)	38	114	191

Table 2: Mangahewa MA72 volumetric reserve estimates

1. Produced reserves

Produced volumes to 31 December 1999 are 2.719 bscf of gas and 38,000 barrels of condensate. The exceedence probability of this number is 100%.

2. Welltest boundary model

As mentioned in the Mangahewa-2 section of this paper, the best match of the whole pressure history for Mangahewa-2 occurs when a U-shaped fault system is used with boundaries at a distance of 3800 ft (with a thickness of 59 ft contributing). Using an average porosity 10% and an average gas saturation of 50% the minimum GIIP (assuming the 4th boundary is at least 3800 ft from the well) is 50 bscf. The exceedence probability of this value has been placed at 95%, due to the very good match of the build-up analysis to both the flowing and build-up pressures in this test.

3. Material balance data

From the two pressure measurements and the volume of gas produced between the two surveys an estimate of the GIIP seen by material balance can be calculated by using the P/z method and Havlena and Odeh method. The methodology for the two procedures is detailed earlier in this paper.

3.1 P/z maximum pressure method

This method only uses the maximum pressures recorded during the various build-up surveys. The absolute pressures recorded will be a function of the shut-in time and gauge resolution (the latter should be within 1 psi). The calculated figure of 117 bscf has been assigned an exceedence probability of 60% as it is a reasonably confident number but not as accurate as the extrapolated method (3.2).

Method		GIIP (bscf)	Gas UR (bscf)	Exceedence probability (%)
1.	Produced reserves to 1 August 1998	-	2.7	100
2.	Welltest Boundaries based on November 1998 analysis	50	35	95
3.1	Welltest Material Balance P/z method			
	Maximum pressure recorded	117	82	60
3.2	Welltest Material Balance P/z method			
	Extrapolated pressure method	105	74	70
3.3	Welltest Material Balance			
	Havlena and Odeh method	100	70	70

Table 3: Mangahewa Field performance model reserves estimates.

3.2 P/z extrapolated pressure method

This method uses the extrapolated pressures obtained from welltest analysis. The calculated pressure will not be affected by the shut-in time directly however, the longer the survey, the easier it is to get a good fit to the data. The last survey carried out was for almost 4 months giving high quality data. For this reason the calculated GIIP value of 105 bscf has been assigned an exceedence probability of 70%.

3.3 Havlena and Odeh

The Havlena and Odeh method is a much more sensitive tool for establishing if a reservoir is being influenced by natural water influx or not. However, with only approximately 2% of the total GIIP having been produced to date it is impossible to say whether or not MA72 is experiencing aquifer support. The calculated GIIP value of 100 bscf has also been assigned an exceedence probability value of 70%.

Recovery factor

The ultimate recovery has been assumed as 70% of GIIP. This of course is a somewhat uncertain estimate and it is realised the recovery will very much depend on the amount of GIIP and the development plan associated with that volume of gas. However, some work has been carried out using the permeability blocking method detailed in reference 1 to produce a relationship between expected flow rates with cumulative gas production based in core data. Core was recovered over the MA72 interval from the Ohanga-2 well and interim miniperm data was obtained at a 10 cm spacing. The permeability blocking method is an attempt to take into account the fact that depletion may progress more rapidly in the high permeability strata than the low permeability zones particularly if impervious strata separate these zones. An uneconomic rate of production may be reached before the tighter zones are drained down to abandonment pressure. The miniperm data is divided into groups and it is assumed that each individual group represents a separate and distinct homogenous layer, feeding into a common wellbore. A rate-cumulative relationship may be established whereby the rate is expressed as a fraction of initial rate and the cumulative as a fraction of GIIP. By selecting an appropriate economic limit rate the recovery factor can then be found. It should be noted that, using this method, it is the *relative* values of the different permeability groups (and number of samples within each group) that is important rather than absolute permeability values.

From Figure 14 it can be seen that for the MA72 zone a recovery factor of 70% is equivalent to a rate of 4.3% initial rate. For Mangahewa-2 the initial AOF would be approximately 65 mmscf/day therefore the cut off rate is approximately 3 mmscf/day. Depending on the performance of the zone there is a chance that this recovery factor could be exceeded.

Volumetric models

Volumetric reserves were calculated using the GIIP values mentioned in the previous section and applying a recovery factor of 70%. Table 2 shows the range of reserves for the three different probabilities.

Combination of all values into a probabilistic reserves distribution

When all the reserve estimates are plotted as a cumulative probability distribution a curve can be fitted that should represent the current range of uncertainty. Figure 15 shows the probability distribution together with the data points. Table 4 shows the resulting range of ultimate recoverable (including production) reserves as per FCE internal reporting classifications. Proven remaining reserves as per SEC classification are 51 bscf with Proven plus Probable reserves of 101 bscf.

Overall summary

The Mangahewa Gas Programme has progressed significantly since the initial drilling of Mangahewa-2. Long term testing at Mangahewa-2 was the first stage in an aggressive appraisal programme, designed to evaluate the field extent and determine whether or not commercial hydrocarbons could be produced from relatively tight formations. From remapping studies carried out on 2D data it became apparent that the quality of the PPL 38705 dataset was poor. Regional markers were mapped instead of top reservoir, as top reservoir was not mappable. One major uncertainty the technical team had

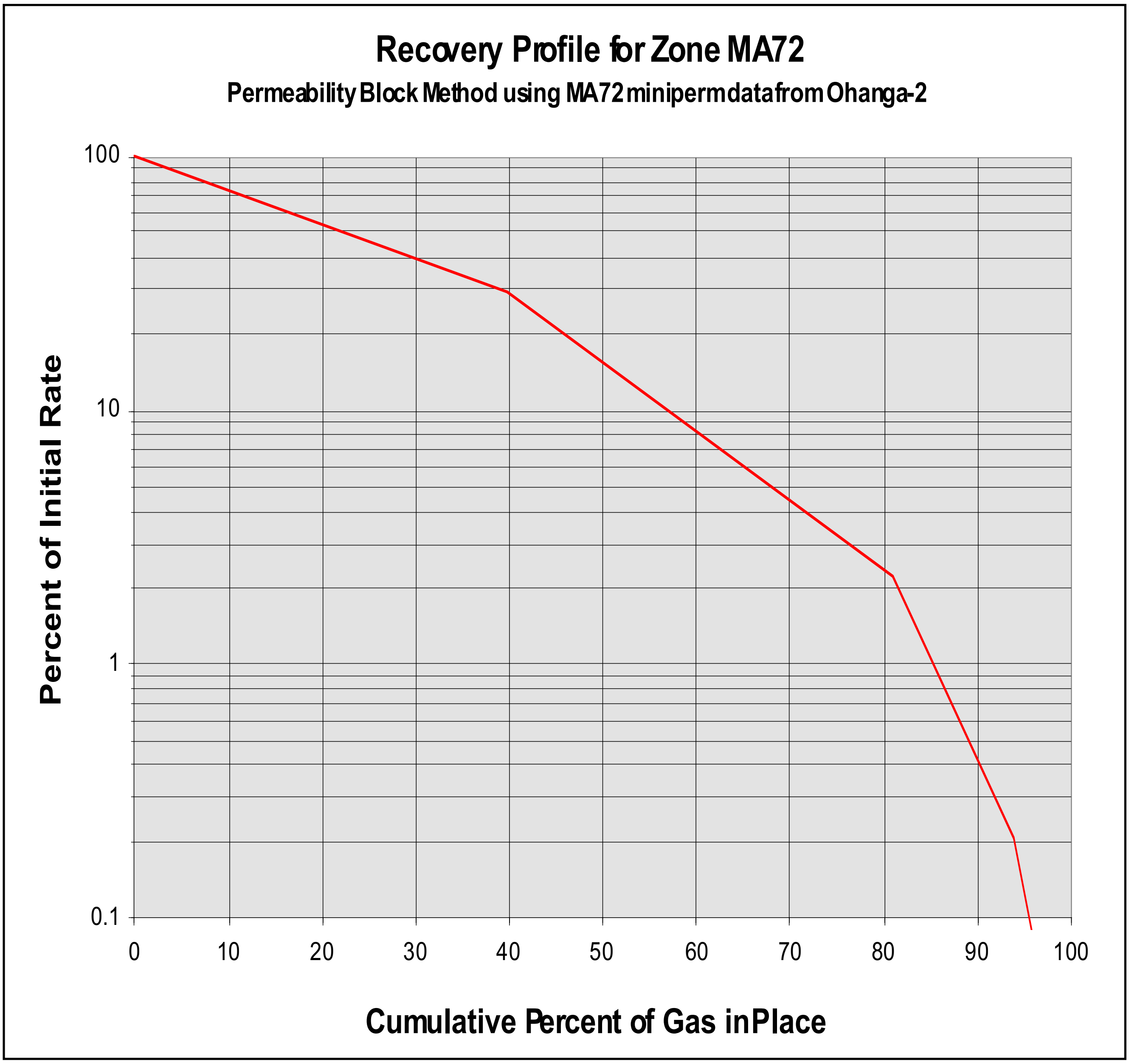

Figure 14: Recovery profile for zone MA72.

was the nature of the top Kapuni event – whether it was chronostratigraphic or lithostratigraphic.

A 3D dataset was aquired in 1998, which answered the above concerns. It was an extremely useful dataset in that it met all of its objectives including imaging the top reservoir and abolishment of mistie uncertainties. The most significant findings of the 3D were that the Mangahewa and Pohokura structures are separate and the producing reservoir at Mangahewa-2 can be mapped with confidence. Confidence in the mapping of the MA72 reservoir was confirmed with the actual prognosis of Ohanga-2, which was only 4 m off prognosis at top reservoir.

Results from the testing of Ohanga-2 confirmed that all the zones (including the MA72 reservoir) were intersected at or near to gas water contacts. Detailed decision and risk analysis (which had formed part of the Ohanga-2 well proposal) had previously identified that a negative result at Ohanga-2 would confirm the existing reserve extent and would result in termination of the appraisal programme. The seismic programme was halted at this point with the Eastern Zipper being cancelled. A mining permit application is currently under preparation and its submission plus relinquishment of the acreage outside the mining permit area will be completed within the time requirements of the existing permit.

The Mangahewa Gas Field has estimated Proven plus Probable reserves of 101 bscf contained entirely within the MA72 reservoir.

Acknowledgements

The Mangahewa Gas Programme grew from the major contributions of a large number of people who participated in the project from the inception of the Deep Gas Study,

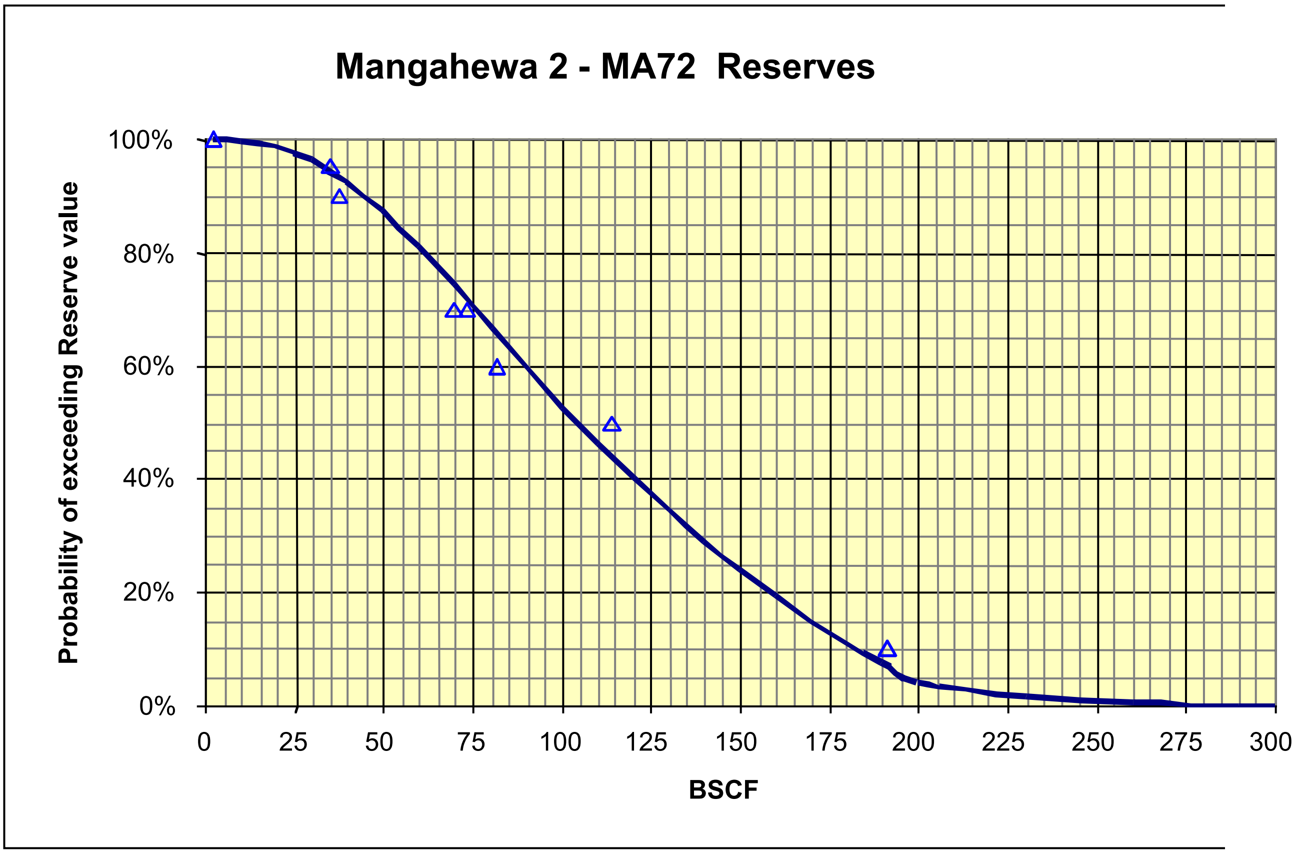

Figure 15: Probabilistic evaluation of ultimate recovery.

Classification of Reserves		Ultimate Recovery
Proven	Gas (bscf)	54.0
	Cond. MMstb	0.377
Proven + Probable	Gas (bscf)	104.2
	Cond. MMstb	0.738
Proven + Probable + Possible	Gas (bscf)	170.1
	Cond. MMstb	1.253

Table 4: Mangahewa probabilistic ultimate recovery based on performance.

through the drilling and testing of Mangahewa-2 and Ohanga-2 and the 3D seismic acquisition and interpretation. The author thanks all the people involved for their input along the way and also thanks Fletcher Challenge Energy for encouragement and support to publish this paper.

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