Some aspects of the transient testing of Bowen Basin coal seams

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ABSTRACT

Since 1987 numerous transient tests have been conducted in the Permian coal seams of the Bowen Basin to estimate permeability. This paper reviews some of the experience with these tests. These results are coupled with observations that have been made on core samples and in mine exposures and guidelines are suggested for future transient test design in these coals.

INTRODUCTION

Coal is a complex medium having some properties which are quite different from the sandstone, limestone and other hard rock reservoirs that the majority of transient testing theory has evolved in. This poses problems in the design and analysis of transient tests in coal.

Researchers are beginning to focus on the problems of transient testing in coal (Zuber, 1990). There has been little written about the problems of testing coal despite the vigourous development of coal seams in the US. Little has been published about testing coals in Australia (Koenig, 1990).

Three wells, which form part of a federal Energy Research and Development Corporation funded research project ERDC# 1464 are discussed, to illustrate the potential difficulties in testing coal in the Bowen basin. The locations of these wells are shown on figure 1.

TYPES OF TEST AND MECHANICAL TEST SETUP

Both slug testing and injection-falloff testing have been used in the Bowen Basin, but the latter has been the preferred method. In this method, which has been applied in open and cased holes of varying diameters and using various types of test tools, a single seam is first isolated by packers. In most cases multiple seams are to be tested within the same hole and a tool which can be reset several times without being withdrawn from the well offers some time savings. However, since Australian coalbed methane investigations have generally been confined to less than 1500m depth, trip times are not lengthy and single set equipment has also been used.

Inflatable packers have been preferred for testing these wells, mainly because of the perceived better conformance (seal) of the packer to the wellbore in rugose hole, but also from a desire to avoid potential problems with hookwall devices slipping or not gripping properly in open hole, or difficulties being able to supply sufficient weight for setting in shallow holes, and from a desire for a higher degree of control over the pressure applied by the packer to the packer seat area. Little testing has been done with compression set packers in coalbed methane testing in the Bowen Basin, but they may have applications in cased holes.

Usually the tool has a straddle configuration with a packer above and below the coal seam. It is usually desirable to set the packers in unfractured roof and floor strata as close as practicable to the seam boundaries, to eliminate any concern about what sediments may be contributing to the observed permeability. In cases where open fractures or otherwise permeable rocks adjoin the seam, this may not be possible and then it could be difficult to determine a true seam permeability. In the Bowen Basin, the interburden sediments are usually assumed to be impermeable. They are generally fine grained and all pore space is filled with clays or other minerals.

The packers may be inflated by a variety of methods. Nitrogen gas pressure is supplied through a separate inflate line which is taped to the outside of the tool or an integral part of an umbilical containing surface readout gauge signal wires. Other variants use the the test string fluid to transmit a surface pressure via the test tubing and a setting tool which can direct the pressure to either the packers or to the seam. With this arrangement, the packers must be able to be vented against inflation fluid or annulus hydrostatic to allow them to collapse properly.

Water is the preferred test medium. The low compressibility offers a low wellbore storage effect when efforts are made to minimise the test interval by shortening the packer spacing and by injecting through the narrowest practicable tubing. Coiled tubing has been used for testing in a few cases.

Downhole gauges are usually run and these should be high precision and high resolution gauges to assist the modern interpretation methods which use the derivative of the pressure with logarithm of time.

Surface readout is optional. It is desirable but also expensive and adds complexity and may therefore reduce mechanical reliability of the test system. On the other hand it may allow the diagnosis of behaviour which is crucial to injection/falloff timing, providing superior quality of tests. In injection falloff testing with water a degree of surface readout may be obtained by monitoring surface pressure throughout most of the test. The falloff is normally then only monitored until just prior to the wellhead pressure declining to zero, to avoid changing liquid level afterflow effects in the late time falloff data. If a downhole shut-in device is available it may be closed (then) to extend the falloff. Having both downhole shut in and surface readout introduces significant test system complexity.

The rates of water injection used have usually been very low (< 5 litre/min). Therefore friction effects may be neglected and a quite precise estimate of bottomhole pressures made from surface pressures. However the behaviour of the pressure derivative may be affected and further study of this aspect is required.

Quite accurate control over rates has been achieved using precision regulated fluid drive of small chemical injection triplex pumps, with constant cross checking by tank gauging in 5 litre increments. This may obviate the need for falloff testing in some cases. In one case a constant rate injection test of more than 15 days duration has been successfully executed.

PROPERTIES OF COAL SEAMS IMPACTING TRANSIENT TESTING

Coal seams are not homogeneous. When considering the continuity of the Permian Rangal coal measures shown by outcrop and coal exploration drilling and in mine exposures over large distances in the Bowen basin, it is tempting to ascribe constant properties to a coal seam. A closer look at an exposed seam will however show that these coal seams are layered. The layering is often very fine when considering the bright and dull lithotypes which are immediately obvious in cores. For practical purposes, these finer layers are usually grouped into coarser packets. These packets or plies can be traced over a certain distance, but the appearance of the plies does change. The plies are sometimes separated by or contain thin stone bands (clays, shales, tuffs, etc.). Thus we are dealing in reservoir engineering terms with a layered reservoir.

Research at the James Cook University as part of ERDC# 1464 has demonstrated that the bright and dull coal layers have different microstructures (Gamson, 1990). This causes them to have different diffusivities in different directions - they will behave very differently in terms of fluid flow in response to an applied pressure drop. The dull layers are usually predominantly comprised of bundles of tubular plant cell structures. Most plant structuring in the bright layers has been obliterated and these consist of nested orthogonal sets of fractures from hand specimen scale all the way down to micron level.

The bright layers are heavily fractured, but the dull layers are rarely fractured at all at core scale. However when looking at a coal face it is also usual to see sets of large fractures spaced 0.3 - 2m apart, which penetrate the entire seam from roof to floor. These features, if open, will control fluid transmission over interwell distances and, if intersected, they will significantly affect the transient response of a well test. Studies of permeability of laboratory scale core plugs and inter-drainhole testing in mines reveals that the coal "matrix" between these larger fractures usually has low permeability (Battino, 1990). Testing of in-seam drainholes drilled in different directions in underground mines (Gray, 1987) and the published U.S. interference testing work has shown that coal permeability can be directional, and strongly influenced by large scale fractures/faults when these are included in the intervals tested.

So in reservoir engineering terms, we are at least dealing with a horizontally anisotropic naturally fractured and layered reservoir.

Of significant interest to the search for commercial reservoirs and the understanding of tests is that diagenetic infills are a common feature of Rangal coals (Gamson, 1990). The mineralisation is often all pervasive filling all pore space down to sub-micron scale and is also commonly seen in the larger fracture faces. Sometimes mineralisation appears to be directional (filling one cleat direction only). A range of mineral fillings are detected - calcite, illites, smectites and kaolinites. This diagenetic overprint can further significantly affect the coal seam transient response.

Laboratory studies (McKee, 1987) indicate that the permeability of coal is very stress sensitive. A mere 100 psi (15kPa) change in net stress could be expected to change the permeability of a 2md coal by 30 - 100%. It is difficult to conceive of an effective transient test in a modest permeability coal which would not change the pore pressure and hence the net stress by at least 100psi at the well face.

When drilling a hole into a stressed elastic formation, rock mechanics theory indicates that a zone of stress concentration will be created around the hole with diminishing effect extending for a distance of several hole diameters around the hole. This zone of increased stress should also be a zone of lower permeability. The effect is hardly noticeable in hard rocks, which have a lower permeability sensitivity to stress. In coals, a stronger reduction can be expected. This has been noted in reports of underground mine drainhole experiences where the permeability of the so-called abutment zone near the face is demonstrably reduced.

Coal is a very soft medium compared to "normal" reservoir rocks. The Young's modulus is about 1/7th and the Poissons ratio is nearly double that of associated sandstones and siltstones. Coal will plastically deform or "creep" significantly. Palmer (1992) mentions a "plastic failure zone" around a caved coal wellbore. Some plastic deformation will probably occur around any borehole in coal.

Coals are easily damaged. The infills mentioned above are easily disturbed or altered by any introduced fluid, as is well known from conventional petroleum reservoir experience. Also, almost any chemical, including water, will be adsorbed onto the coal internal surface area, resulting in swelling and permeability reduction. The typical cleat porosity (water accessible porosity) of a coal is usually less than 2%. This means that even small volumes of introduced fluids will be distributed through large volumes of coal, possibly creating quite deep damage.

The reader will appreciate from the above that coal seams are complex reservoirs. The testing of coal seams is difficult, with further research required and great care needed in field procedures and quality control.

REASONING FOR PREFERENCE OF INJECTION FALLOFF TESTING

The concept of a radius of investigation seems more readily definable with this type of test. The injection-falloff method offers the advantage of an ability to cross-check seam behaviour during both injection and falloff periods, given sufficient control over the accuracy and steadiness of pump rates during injection.

A potential problem with injection falloff testing of coal seams results from the large stress sensitivity of coals as is discussed by Close (1991,p30). DST testing with a partially evacuated string is sometimes recommended instead. However, this method could limit the flow period duration (assuming the well will not flow unassisted to surface) and risks introducing gas if the seam is nearly gas saturated. The slightest gas phase makes the test interpretation more difficult.

It is normally assumed that Bowen basin coals are water saturated at the initial reservoir pressure and temperature as found. At this stage of our knowledge of the basin, this is arguable, but seems reasonable.

It has been assumed that provided sufficient care is exercised to keep injection rates and hence injection overpressures below a predefined limit, which corresponds to a minimum expected horizontal closure stress, these tests should provide useful and valid information for exploration reconnaissance, and allow testing of a greater volume of reservoir. Even if cleat opening does occur, the comparison of injection period data (late time data at high overpressure) with falloff period data (late time data near initial reservoir pressure) should detect a consistently higher permeability for the injection period, which provides a limiting maximum permeability estimate.

Likewise, in a DST situation, the permeability estimate from flow period data might be expected to be lower than the build-up period estimate, on account of the higher net stress on the coal being "investigated" during the flow. However the decreasing rate profile of a DST flow period (flow not reaching surface) will require special analysis methods for variable rates to see this and the results may be masked by changing liquid level afterflow.

Therefore on account of the possibility to extend the injection period at will and thereby investigate as large volumes of coal as possible, in order to avoid introduction of two phase conditions near the wellbore and in order to have the possibility to directly and easily compare injection and falloff data, the injection-falloff test has been preferred. It also simplifies operations in some testing system configurations.

EXAMPLE WELL # 1

Well 1 was drilled in 1991 as an 8-1/2" hole which was cased and perforated prior to injection falloff testing in the Rangal coal measures in a single seam. The location of the well is shown in Figure 1. Core recovery showed this to be low volatile bituminous coal with an ash content of about 15% (adb). The well was drilled into the overthrust section of the major Burton Range thrust fault and permeability was expected to be high. The well did not target the thrust plane itself, but rather a broader zone of enhanced vertical fracturing associated with the thrust ramp anticline.

The data recorded during the pre-stimulation test indicated a low permeability reservoir. Figure 2a and 2b show the log-log and semi-log plots. The interpreted results were as follows:

Permeability 0.065md

Skin + 0.4

Notice the flattening of the log-log pressure data, the sharp disturbance to the derivative (arrowed) and the change in semi-log slope at the end of the test period. Although the wellhead pressure did reach zero during this falloff, this flattening occurs before that happened and represents a true formation response.

Following hydraulic fracturing with 100,000lbs of 20/40 mesh sand and 52,500 USgals of borate crosslinked guar gel, the well was retested, mainly to determine the fracture properties. The log-log type curve match shown in figure 2c indicates that the reservoir permeability must have increased, and an estimate of 3.2md was made from log-log type curve matching of the combined fracture-formation response even though the test was not long enough to directly measure the permeability. The post stimulation production which was measured following the test was also too high to be coming from a seam with the interpreted pre-frac permeability.

It is postulated that the flattening response represented the sharp contrast in permeability as the pressure transient encountered a large (seam thickness scale) open natural fracture system quite close to the well. Such fractures were accessed by the stimulation treatment and by subsequent post-stimulation testing and production.

This example illustrates a key problem of coalseam testing. The matrix permeability between large scale fractures will be very low. The spacing on these large features is usually a few feet to a few metres in exposures that the author has personally inspected. The chances of hitting or even getting very close to these near vertical planar fractures with a slimhole well are very small. This means that statistically speaking, the chances of measuring a low permeability which does not properly represent the permeability that would govern subsequent field development are high. Further, the low permeability that will be encountered, along with the high probability of a damaged zone around the well will mean that the test will often not investigate far enough into the coal to detect these important fractures.

If the post frac estimate of permeability of this well was correct, better production response should have been achieved. This may be a sign that that the hydraulic fracture at this location was of limited propped radius (98ft) and horizontal and that the gel used during the fracturing has severely damaged the natural fracture system in the coal. Reports from the US of severe damage from crosslink gel treatments have been recently published. It may also be that the permeability of the "matrix" coal feeding into the large scale natural fracture network is not sufficiently high, (although the microstructure at this location was reported to be open and relatively unmineralised). It could also be that the post frac indication of higher permeability is not sufficiently accurate i.e. perhaps only 1md, but still much higher than 0.065md. Both sufficient major fracture system permeability and sufficient internal permeability of the large blocks of coal which would feed gas to this system are required for commercial production.

EXAMPLE WELL # 2

Well 2 was drilled on the eastern flank of the Taroom Trough west of the town of Banana (figure 1). The well was partially cored through the Rangal coal measures and tested in one seam in HQ size hole (96mm dia). Core recovery indicated a 5.2m thick clean medium volatile coal with good cleat development but with siderite (?) mineralisation in the cleats.

The structural target of the well was a NNW trending horst between a thrust and a back thrust. Flexure of the coal seams was only slight at the well location as seen on seismic. This well was tested in a single seam at 512.5m GL using a CSIRO straddle packer tool run on coiled tubing. Three successive injection falloff tests were run using different injection rates and with correspondingly different excesses of injection pressure over bottomhole pressure. The tests were all short. The longest injection period was 72 minutes.

Figures 3(a),(b),(c) show the falloff period semilog plots for each test and the interpreted results were as follows:

Test No.	Injection Rate (litre/min)	Injection Period (hrs)	Excess Pressure (bar)	Permeability (md)	Tested Radius (m)
1	0.7	1.08	13.8	0.47 (0.32)	2.0
2	0.2	0.91	4.1	0.63 (0.43)	2.1
3	2.3	1.20	24.5	0.78 (0.53)	2.2

The permeability figures in brackets are more accurate following correction of the water viscosity from a value of 1cp used in the early interpretation to a more realistic 0.68cp at the anticipated bottomhole temperature at this depth. The change of slope on the falloff below 62 bar shown in figure 3(c) has been interpreted as a sign of natural fracture or cleat closure below that pressure and it has been suggested that this test may illustrate the dangers of injecting at too high a rate, causing in turn too high pressure and artificially enhancing the measured permeability.

The pressure created by the injection should in the case of a perfectly clean and undamaged completion decrease moving away from the borehole wall and into the coalseam logarithmically with distance. At the indicated "closure" time within 6 and 12 inches of the borehole wall, the excess pressure should have been respectively reduced to 59 and 33% of its value in the well. Therefore at an early stage of the falloff, most of the area investigated or disturbed by the previous injection is above the net stress level that might allow cleat opening (i.e. closed). It is also noteworthy that the permeability from test 2 at lower injection rate and pressure is 30% higher than for test 1.

The radius of investigation was nearly the same in all tests, so it is unlikely that test 3 "saw" a high permeability feature 2.15m from the well that the earlier shorter tests did not.

It is postulated that these differences have another possible cause. Assume cleat opening of natural fractures adjacent to the well could occur only at the highest rate and pressures of test 3. This in turn allowed the test to more completely access the full natural cleat system surrounding the well. The earlier tests had somehow been restricted to only a part of the cleat system on account of the higher stress due to lower injection rates allowing important "feeder" fractures to remain closed (or blocked by damage). Therefore it might be that the higher value is valid.

This example was chosen to illustrate a key concern in test design between pumping at too low a rate and not properly accessing the permeability and pumping too fast and creating higher than natural permeability levels.

EXAMPLE WELL # 3

Well 3 was drilled on the Eastern flank of the Taroom Trough, between Moura and Theodore, as shown on figure 2. The well was initially drilled and tested as a HQ corehole, but was subsequently enlarged to 8-1/2" size, retested in several seams and cased with 5-1/2" casing. The # 4 seam was selected for stimulation and production trial, as part of ERDC project # 1464, and extensive testing and analysis was conducted on this seam.

Core recovery indicated a well cleated relatively clean high volatile A bituminous (VRo = 0.81) 3m thick coal with some calcite and clay mineralisation.

The structural target of the well was a relatively undisturbed area thought to be in a lower horizontal stress regime on account of normal faulting reported by the coal explorers and significant departures from a regional north-south course in the Dawson River, to the west of the well. An earlier well drilled 400m to the south of well 3 had recorded permeabilities in excess of 10md in some seams. Seismic showed no significant faulting in the vicinity of either well.

Prior to hydraulic fracturing, the well was retested first by short injection falloff and then by extended injection falloff test. So there are several tests in different hole sizes and run under different conditions to compare in this well. In addition, following the fracture treatment, a very long (15.7 day) injection test was conducted to establish the stimulation effectiveness.

There is therefore a very extensive data set from this well and this # 4 seam in particular.

Table 1 shows a comparison of the permeability estimates from the tests of the well 3 and its neighbour well only 400m away. Note the variability of the interpreted permeability in some seams. These differences reflect interpretation difficulties, inadequate test length, and natural heterogeneity. The inconsistencies in extrapolated pressures in the same seams beween wells are probably also indicators of inadequate test duration and interpretational shortcomings.

Permeability variability is however a feature of these Rangal coal seams in particular and coal seams in general. Numerous production wells scattered through the area could be expected to display correspondingly quite variable production behaviour.

Figures 4a and 4b show the log-log and semilog plots of a 3.5 day injection test conducted at a constant rate of 1.0 litres/min on seam 4 of the Rangal measures in this well. Figures 5a and 5b are the corresponding plots of the 6.7day falloff period which followed. A downhole shut-in tool with surface readout which was developed by the CSIRO Division of Geomechanics was used for this work. Notice the suggestion of double porosity (fracture?) behaviour on both semilog plots and as confirmed by the derivative behaviour on both log-log plots. Note also the long period required for transition from the fissures to fissures plus matrix system. The interpretation of this data yields the following results:

		LOG-LOG	SEMI-LOG
INJECTION	k (md)	1.9	2.7
	s	-3.2	-0.68
FALLOFF	k (md)	2.0	2.6
	s	-2.0	-0.88

The injection and falloff log-log plots are slightly different at early time and the spacing between the parallel semilog straight line segments of the injection and falloff tests is different. This may be partly due to a longer wellbore storage effect in the injection period caused by the larger wellbore volume being compressed. There is probably another factor related to the compressibility of the coal also. The match between semilog and log-log estimates of permeability is considered reasonably good, considering the possible non-uniqueness and lack of resolution of manual type curve matching to a limited number of published curves. Using a value of 2md for the permeability, the estimated radius of investigation of this test was 44m. It seems reasonable to conclude that that level of permeability would govern the short term production response. The good agreement between injection and falloff estimates of permeability from late time (long term) data at significantly different actual net stress levels indicates that there was no obvious significant artificial enhancement of the measured permeability despite the wellbore injection pressure reaching 168psi above initial.

Note that despite the long duration of the injection test (3.5days), the investigated radius is rather small on account of the low permeability and the high compressibility of the coal. It is time consuming and therefore expensive to transient test significant (representative) volumes of coal.

Immediately prior to conducting this test, a short test was carried out to give preliminary information about injection rate for the long term test. This was a 1.6hr injection at 0.54 litres/min followed by a 5hr falloff and the data from the falloff are shown in figures 7a and 7b for comparison with the extended falloff data. What is apparent from this comparison is that it might be inappropriate to draw a semilog straight line through the late time data of the shorter test, even though a reasonably clear straight line appears to have developed, since this would correspond to the transition period in the long test. If the permeability is taken from this section of the data with flatter slope, an estimate of 3.9md, skin + 0.8 is found, suggesting a slight reduction in permeability and a slightly damaged situation. The estimated reservoir pressure is then 721psia.

The complexity displayed by the extended pre-frac test is all the more interesting if one relates it to two other tests that were conducted in this well. Following initial coring a short test was run in the HQ (96mm) hole. This test was run at increasing injection rates for 2 hours up to 3.5 litres/min. It yielded a permeability estimate of 4.7md, a skin of -1.9 and a reservoir pressure of 721psia. Later, the hole was opened to 8-1/2" and prior to casing the well, another test was run on this seam at increasing injection rates for 1.7 hours up to 5.3 litres/min. It yielded a permeability of 4.5md, a skin of -1.6 and a reservoir presssure estimate of 754psia. The reasonable agreement between the permeability estimates from different tests run at different injection rates in different sized holes, using different tools and several months apart is encouraging. The significantly higher reservoir pressure estimate in the 8-1/2" open hole test causes concern and it is not known what the cause of this difference was.

The extended (15.7 day) post frac injection test at 2 litres/min is shown in figure 8 and it has been interpreted by type curve matching to be indicating a horizontal fracture was created with a propped radius of about 110ft. This is in keeping with simulation studies of the fracturing data itself, which have indicated two horizontal fractures were formed. The long duration of this test and the shorter than anticipated fracture radius have resulted in the transition to radial flow almost being complete within the test duration, so that in this rare case it is possible to obtain a clear picture of the actual level of stimulation achieved by the frac by computation of the skin and comparison with the pre-frac skin.

The post frac test interpretation yields:

Permeability 4.2 md or less

Skin -5.4 or less

Fracture dimensionless conductivity 40

Effective average fracture width 0.43 ins

Reservoir pressure 714.5 psia

From the skin value we can say that an adequate level of stimulation was achieved by the fracturing. Despite the fairly large interpreted average frac width, the permeability connected to the frac does not seem to have been significantly reduced by residual stress effects.

When the well was being flowed back, some gas was noted, suggesting a small free gas saturation may have been present during the extended pre-frac test. The companion well referred to earlier had been on production from multiple seams for about 8 months prior to the pre-frac testing in casing. It is therefore possible that the pre-frac extended test detected a small free gas saturation which has reduced the effective permeability to water from about 4.5md to around 2md. When the fracturing was carried out, free gas was pushed away or caused to readsorb by the high pressures. The subsequent extended post-frac injection test saw a permeability closer to the original value then. The well produced between 80 and 100Mcfd gas and 90 to 15bwpd for about six months from this seam, then the gas rate declined sharply. The well was produced for more than 12 months. The production data have been simulated using the SIMED model (Spencer,1987) by researchers at the University of NSW. That work will be further reported on in the end of grant report for ERDC 1464.

DISCUSSION

Example 1 illustrated that even fairly lengthy tests may be unduly influenced by the low permeability of near-well unfractured coal, to the extent that potentially important higher permeability features not intersected by the well could fail to be included in the overall permeability assessed by that test.

Example 2 illustrated that the permeability indicated by a short well test in coal is rate sensitive.

Example 3 showed that significant reservoir complexity may be revealed by an extended test of a coal seam. This particular complexity could be variously caused by a dual porosity/permeability system or by the presence of a gas saturation due to previous neighbour well production. Despite these possible complexities, however, a reasonable consistency arises out of all tests conducted over a large range of times and at a variety of injection rates on the same seam.

One important consequence of the softness and high compressibility of coal is that testing theory for describing the pressure response for a porous medium which is deforming as it is being tested is not readily available. Interpretation of such tests may currently be impossible. Zuber (1990) comments on this aspect of the early time data in his examples.

A consequence of the layered, fractured and cleated nature of coals is that the flow geometry of such a test may be significantly different than might be imagined by the interpreter, so that even if the current (radial flow) theory appears to fit the data, erroneous conclusions may still be drawn. At best, over a long test where pseudo-radial flow appears to be holding, some geometric average of the minimum (e.g. butt cleat ?) and maximum (e.g. face cleat ?) permeabilities may be measured.

If the minimum direction horizontal permeability is very low, it will bring the average down, even if the maximum direction value is quite high. A strong contrast in directional permeabilities will also cause a lengthy transition to pseudo-radial flow, making premature termination of the test and wrong interpretation of permeability (e.g. from a simple semi-log plot) more probable (Hale, 1979).

Where very thin well-cleated bright coal layers dominate the measured test permeability, the thickness of these will be very difficults to establish, so that only the seam capacity (md.ft) will be accurately determined. The true thickness conributing to flow and therefore the magnitude and meaning of the permeability is debateable.

RECOMMENDATIONS FOR DESIGN OF INJECTION FALLOFF TESTS

One usual test design constraint has been to keep the injection overpressure as low as possible. Therefore, when the permeability is not known a priori, setting the required rate is difficult. However if sufficiently high resolution pressure gauges are used, permeability can still be determined from very flat slopes in rare high permeability (or post hydraulic fracture testing) situations. The result has been the adoption of very low injection rates in recent tests - say less than 0.5l/min in tests which initially respond as tight or damaged - to minimise the build-up of test pressure within the required injection time.

This is a very critical constraint. The radius of investigation of an injection test in which radial flow prevails is proportional to the square root of the product of the permeability and the injection time. Having to cut the test short during the injection period on account of having reached a predetermined injection pressure, above which fracture opening may occur, or during the falloff period to avoid falling liquid level afterflow effects can result in tests which investigate only small volumes of coal around the well. For the explorationist, this is believed to be dangerous, possibly resulting in unrepresentative tests.

Modern natural fracture theory (Lorenz, 1990) envisages an insitu anisotropic horizontal compressional stress state under which fractures may be open, provided they have not been infilled by diagenetic processes. In that situation, the concept of staying below a cleat opening pressure during injection may be fallacious - any increase in pore pressure may cause further dilation of already open cracks, leading to permeability enhancement, and any reduction of pore pressure such as would occur during the more familiar drill stem testing (flow-buildup) would result in crack closure and potentially severe permeability reduction near the well.

There also may be a need to "push through" a zone of more highly stressed coal around a well in order to access the true permeability beyond.

Therefore it is suggested to test coals at a minimum rate of around 2litres/min. If breakdown (microfracturing) occurs, it is unlikely to propagate far in relation to the radius of investigation of the test. The test should be run long enough at a constant rate to see a geologically predefined (based on minimum fracture spacing expectations) volume of coal. It is preliminarily suggested that this probably should be about 20ft minimum. That will typically require an injection period longer than 12 hours unless there are conductive fractures quite close to the wellbore or intersecting it.

CONCLUSIONS

Great care must be exercised in transient testing of coal seams, because a variety of complex behaviours affect such tests.

In general quite lengthy tests (greater than 12 hours injection at constant rate) are recommended in exploration holes to obtain an initial assessment of an area, unless the test is immediately indicating high permeability. A short test runs a high risk of wrongly attributing low permeability to a seam because it probably will not sufficiently access the major fracture network which dominates field scale coal seam permeability.

Further research is required to develop interpretation methods in these soft and stress sensitive coals. There appears to be an urgent need for a clear guideline as to the injection rate and excess over reservoir pressure to test at in an unknown area.

The dual permeability dual porosity nature of coal seams could result in quite lengthy transition periods and even long tests may not be long enough.

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RANGAL	WELL	No. 3	COMPANION	WELL @ 400m
SEAM	DEPTH(mGL)	PERM. (md)	DEPTH(mGL)	PERM. (md)
0	403.3	6.3	421.0	3.3
1/2	440.7	13.6	465.0	13.9
3	468.1	0.1	492.6	26.6
4	502.0	4.5	526.6	0.3
5	536.8	2.1	560.0	0.6
6	561.3	0.5	586.0	0.5
7	591.2	1.7	618.3	-
9	610.0	1.7	628.4	0.2

Table 1. Comparison of permeability in neighbour wells showing significant variability

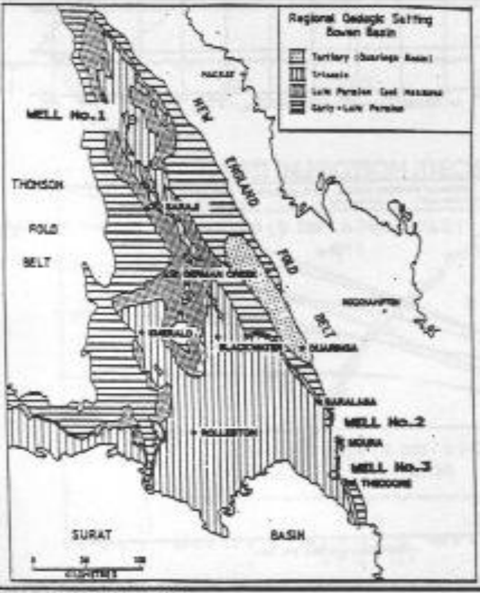


Figure 1. Location of the three example wells

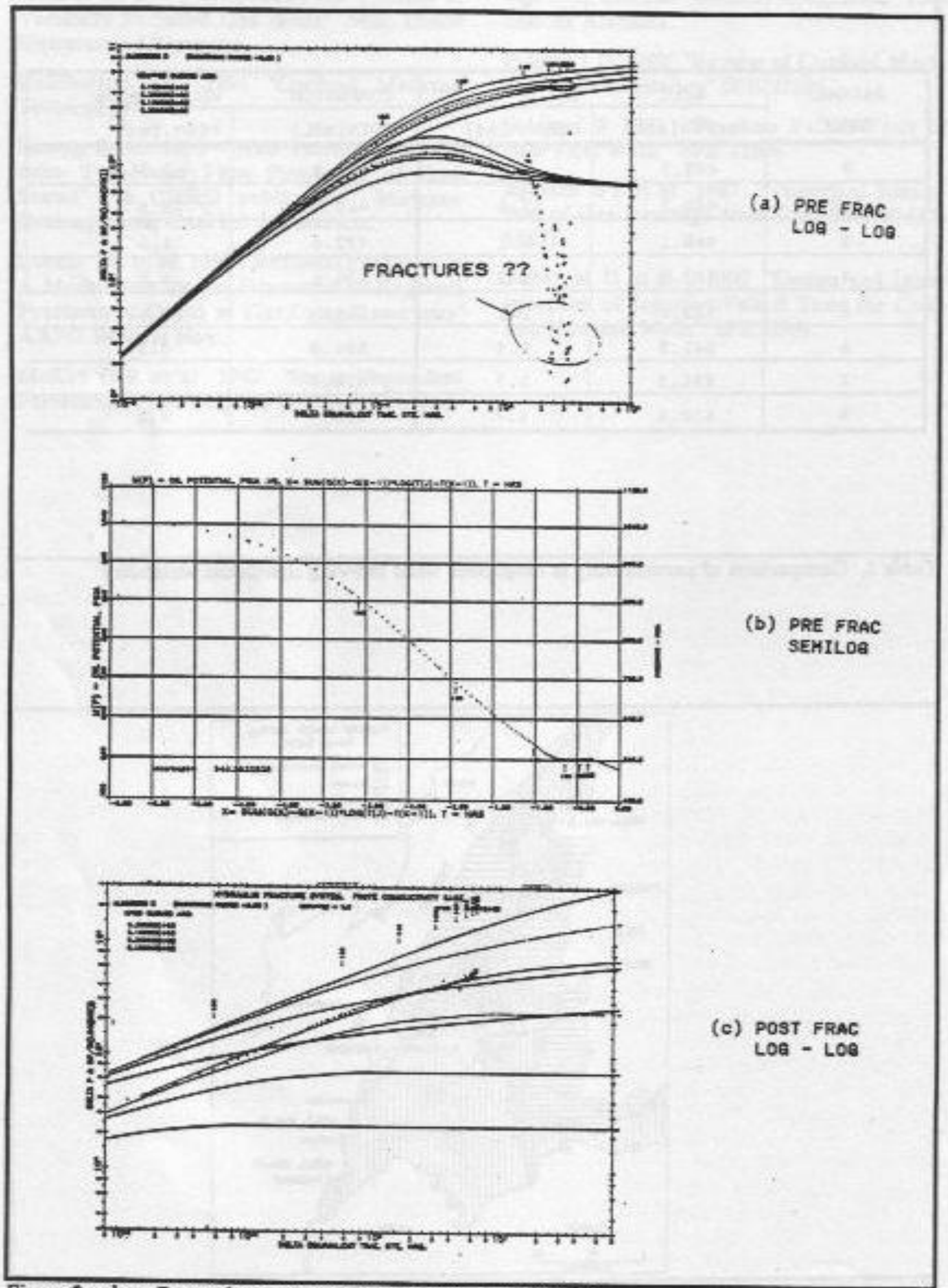


Figure 2. a,b,c, Pre and post frac test results from Well No 1

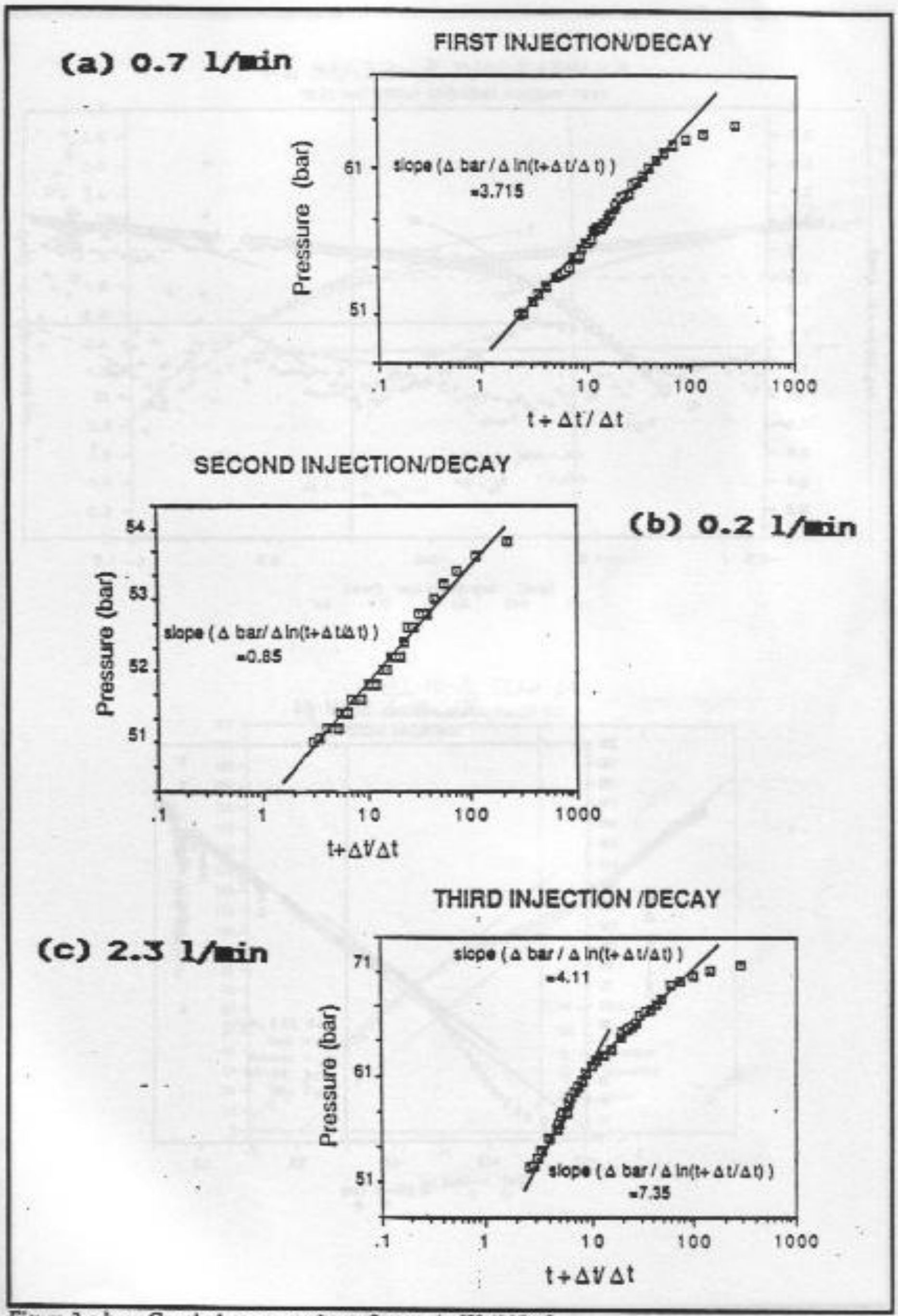


Figure 3 a,b,c Corehole test results at 3 rates in Well No 2

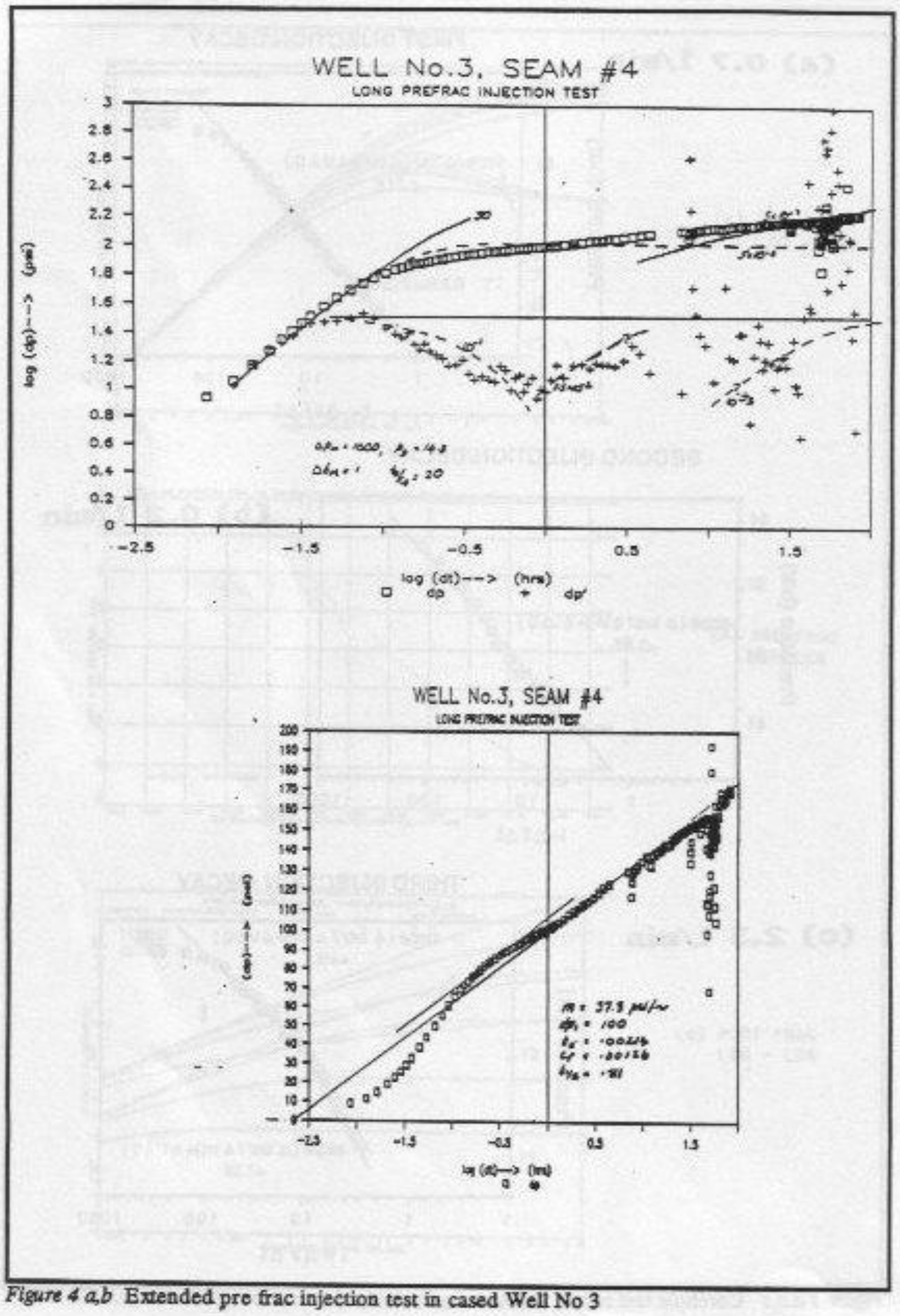


Figure 4 a,b Extended pre frac injection test in cased Well No 3

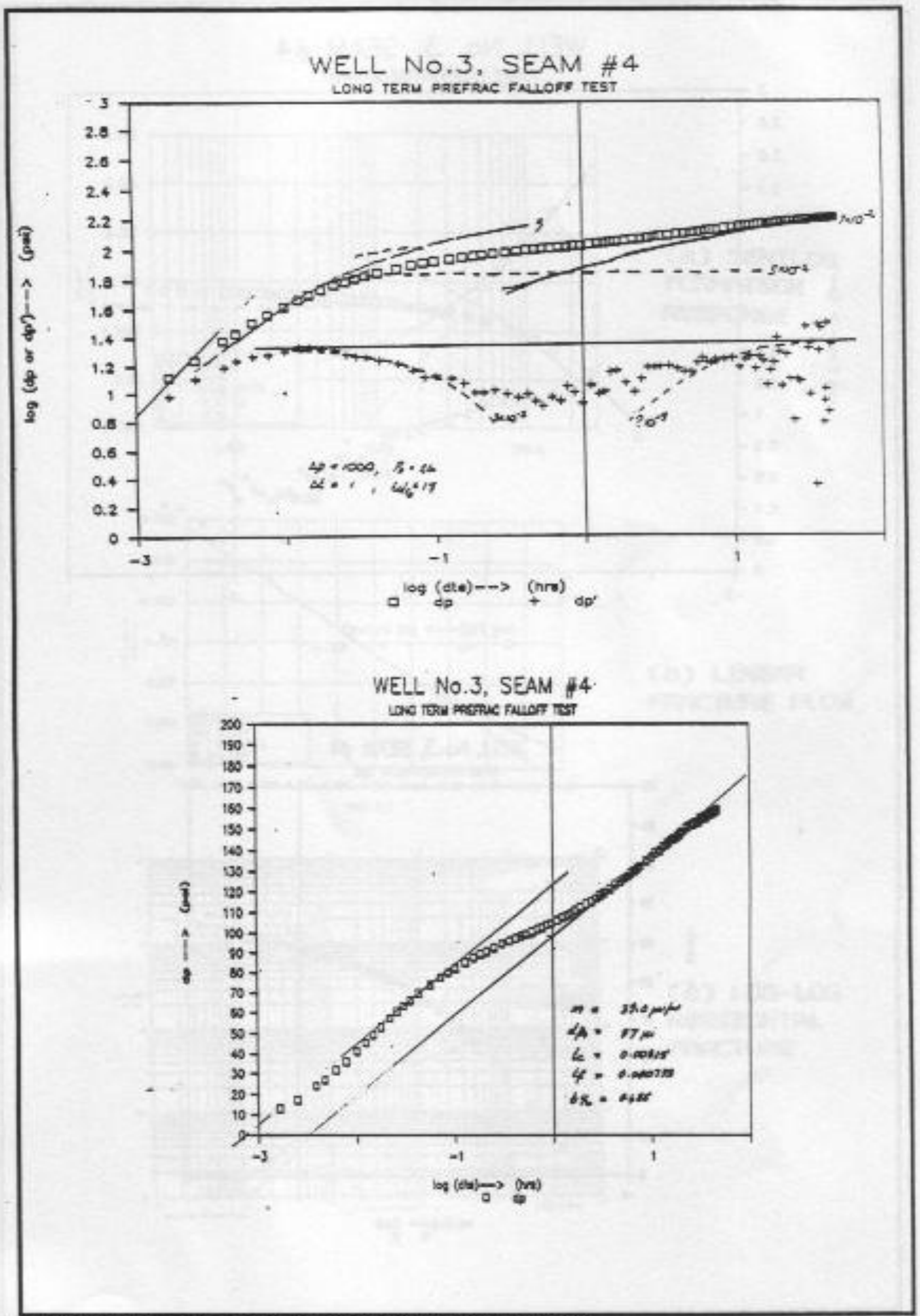


Figure 5 a,b Extended pre frac falloff test in cased Well No 3.

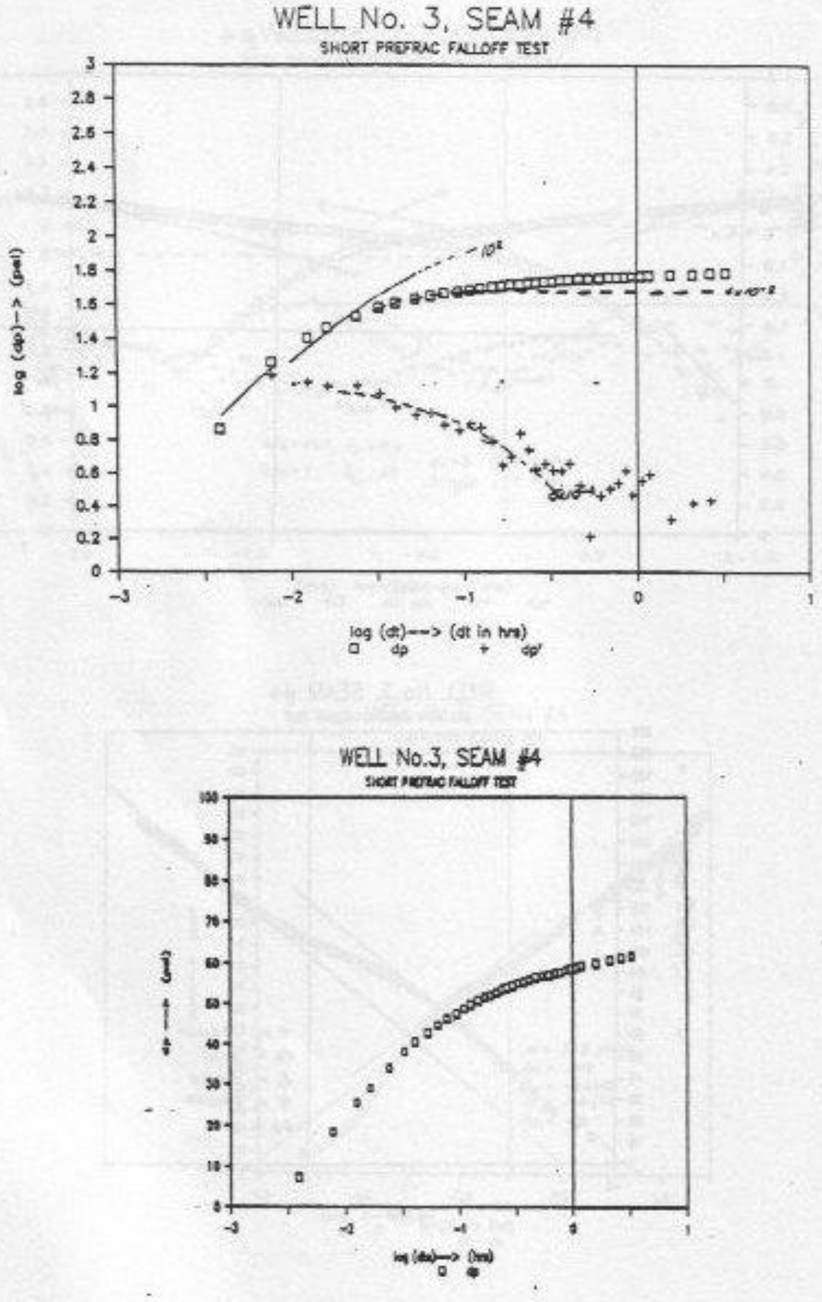
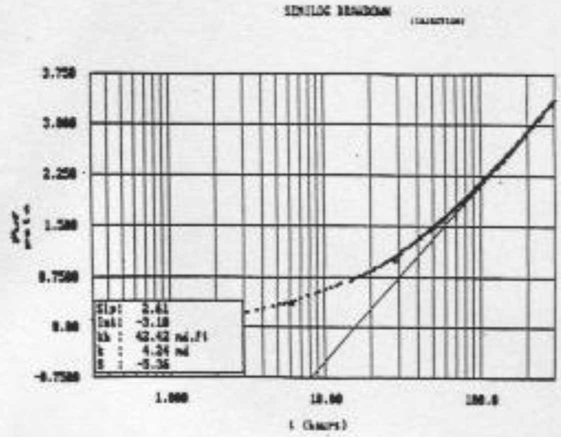
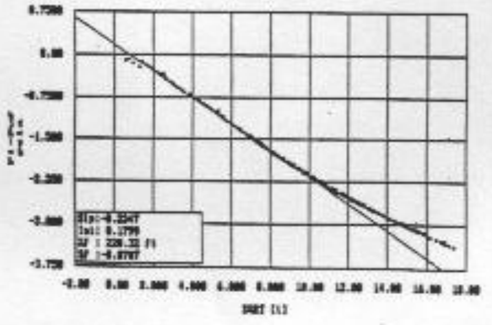


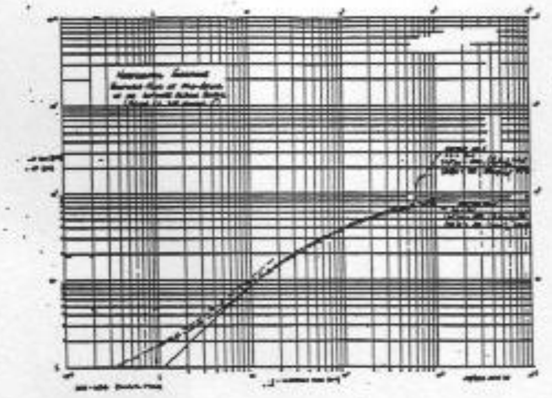
Figure 6 a,b Short pre frac falloff test in cased Well No 3.



(a) SEMILOG FORMATION RESPONSE



(b) LINEAR FRACTURE FLOW



(c) LOG-LOG HORIZONTAL FRACTURE

Figure 7 a,b,c Extended post frac injection test in Well No 3.