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Well-Testing CBM-Wells Definition of Major Anomalies with Oil and Gas Reservoir

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***Abstract*—Coal Bed methane reservoir is a naturally fractured reservoir in which coal serves as both the source and the reservoir rock. The properties of this rock which include low permeability and porosity as well as a systematic fracture network affect significantly the pressure transient response of such reservoir. This differs from the pressure response of a conventional oil and gas reservoir**

The anomalies resulting from well-testing such wells using pressure transient analysis was studied in this report. A pseudopressure model approach that is traditionally used to tackle this problem and which involves rock mechanical properties of the coal was described and used to investigate the anomalous wellbore storage and significantly large skin value observed in the derivative response of a CBM field reported in Queensland.

Some interesting inherent features of this type of reservoir were observed. The Stress dependence of permeability and porosity, rate dependent skin contribution due to stress effect as well as gas blocking effect were observed.

Keywords*—*Coal-Bed; Methane; Permeability, Well-test

1. INTRODUCTION

Coal Bed Methane (CBM) is naturally occurring methane (CH_4) with small amount of other hydrocarbon gases that is contained in coal seams which results from subsurface physical and chemical processes. It is often produced from shallow depths with associated large volume of water of variable quality. CBM resources are said to represent valuable amount of natural gas within and outside of areas of conventional oil and gas production.

Coal seams are said to represent the source for the methane gas as well as the reservoir. Due to their enormous amount of surface area, they can hold an immense quantity of methane. This large internal surface area is reported to store on the order of six to seven times more methane gas than equivalent volume of rock matrix in a conventional gas reservoir. The CBM gas exists in the coal in three basic states: as free gas, as dissolved gas in the associated coal water and as “adsorbed gas” on the solid surface of the coal.

However, the nature of coal-seams being naturally fractured and the solid coal with infinitesimal porosity and permeability values accords it some special features that distinct it from other conventional oil and gas reservoirs. These features have resulted in anomalies in well-testing of such (CBM) wells. Several works have illustrated some of the difficulties associated with interpretation of well-testing CBM wells.

The aim of this research is to define major anomalies that result from well-testing CBM wells which differs it from conventional oil and gas reservoir. These anomalies will be interpreted with respect to the geological reasons for their causes.

2. LITERATURE REVIEW

As unconventional oil and gas resources become more expensive and difficult to pursue and with the current dwindling of conventional reserves, the world will continually and increasingly utilise coal bed methane and other unconventional sources as alternative sources of energy. Proven oil reserves for the world in 2013 were 1,600billion barrels[1] compared to resource estimates for Coal Bed Methane CBM that range up to 1,400 billion barrels equivalent oil [2]. Although much of this will currently remain uneconomic to recover, it still represents a resource that will contribute enormously to future energy requirements.

At least 60 countries are known to have appreciable coal reserves, and there is an estimated 13 trillion metric tons of coal in place in the world [3]. The figure is expanded to 25 trillion tons with the inclusion of low-rank coals [4]. Most of this amount is located in 10 countries as given in Table 2.1, generally the finding cost of CBM are usually lower than for conventional natural gas reservoir.

Table 2.1: Coal Reserves in different countries

Country	Billion Tonnes
Russia	4,860
China	4000
U.S.A.	2,570
Australia	600
Canada	323
Germany	247
United Kingdom	190

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Poland	139
India	81
South Africa	72
Others	229

Main constraints to producing the methane are usually lack of geologic characterization of the coals, lack of operating as well as engineering experience in producing the CBM and lack of investment capital. Markets may not exist or the coal may be far removed from markets in that country [4].

2.1 CBM RESERVOIR PROPERTIES

Rock Physical Properties

In contrast to conventional oil and gas reservoirs where the matrix is inorganic in nature, the CBM reservoirs are organic formations which contain about 10-30% inorganic ash. The optimum rank of coal matrix for methane are brittle and friable with low values of Young's modulus and high Poisson ration, this lies in the range between sub-bitiminous-A to low volatile bituminous [2].

Coal's rank which is a measure of the quality and thermal maturity of the organic matter determines the amount of the gas content. The mechanical properties of this solid particle also depend on the rank. Table 2.2 presents the ranks given to different types of coals.

Table 2.2 Ranks given to different types of coals.

Class	Group	Abbreviation
Anthracitic	Meta-Anthracite	Ma
	Anthracite	An
	Semi-Anthracite	Sa
Bituminous	Low volatile	Lvb
	Medium volatile	Mvb
	High Volatile A	hvAb
	High Volatile B	HvBb
	High Volatile C	HvCb
Subbituminous	Subbituminous A	subA
	Subbituminous B	Sub
	Subbituminous C	subC
Lignitic	Lignite A	ligA
	Lignite B	LigB

2.2 ADSORPTION

The mechanism of hydrocarbon gases storage in coal seams differs from the mechanism of storage employed by conventional reservoirs. In the later, free hydrocarbon gases occupy the available void spaces between the sand grain particles, while in coal seams, the hydrocarbon gas (CBM) is held to the solid surface of the coal by a process called adsorption which takes place in the numerous micropores. The relatively large surface area within the micropores and the close proximity of methane molecules on the internal solid surfaces allow the unprecedented large amount of the hydrocarbon gas to be stored in the coal. Some free gas which exists in the natural fractures of the coal and some methane dissolve in the waters in the coal, but the bulk of the methane comes from the micropores. The adsorption mechanism creates the paradox of high gas storage in a reservoir rock of porosity less than 2.5%.

2.3 WATER PRODUCTION

Another distinct feature which contrasts CBM wells from conventional reservoir wells is the normally occurring prolific generation of associated formation waters from natural fractures in the coal. To desorb methane from the coal matrix, this formation water must be significantly removed and this normally takes place in the early life of a CBM well. This large volume of produced water normally occurs in the first or second year of production and then decrease thereafter to a relatively small volume for the remaining life of the well which might be up to 20 years. In contrast, conventional gas reservoirs would keep the connate water of the pore spaces held immobile and significant water production would not be anticipated until the aquifer is encroached which indicates a looming stoppage of gas production.

2.4 GAS PRODUCTION

A decline curve comparison of gas production from coalbeds to methane production from conventional gas reservoirs reveals differences in their mode or pattern of production. Drainage areas and Gas-decline coefficient were determined from coal well-decline behaviour, and the results obtained were compared with reported and also simulated declines in real CBM fields, the powder river, the warrior and San Juan basins [5]. Previous computer simulations have indicated that CBM may be produced for 20-30 years from reservoirs.

The extended producing life of a coal bed well, in contrast to a conventional gas well may be conducive to long term contracts desired by the electric utilities. Coal beds show production rates of methane gas that initially start to increase and then followed by a long period of decrease or decline in gas production. This is as a result of pressure lowering process resulting from dewatering of the coal.

Summarily, the CBM production process has many similarities to the development of gas from conventional reservoirs. However, the major differences between the two types have an immense impact on operations and profitability.

2.5 COAL RESERVOIR ANALYSISPERMEABILITY

This is the most critical parameter for economic viability of a gas containing coal; coal itself is a low permeability reservoir, almost all the permeability of a coal bed is usually due to fractures, which in coal are in the form of cleats. The permeability of the coal matrix is negligible in comparison. The network of natural fractures along with any hydraulic fractures must supply the permeability for commercial flow rates of methane. It is also the most difficult parameter to evaluate accurately [6]. Therefore, the frequency of the natural fractures, degree of fracture aperture opening, direction of face and butt cleats, saturation of formation water, depth of burial, the shrinkage of matrix associated with desorption and in-situ stresses are all factors that can affect permeability. The changing nature of gas relative permeability with water content in the flow path also complicates the determination of the gas effective permeability.

Analysis has shown that even with core tests, accurate measurement of permeability is difficult. This is because coal permeability is a function of stress and values measured in the laboratory on cores and which may not be accurate or representative. More so, since the permeability of coal is also a function of sample size, values measured in the laboratory tend to be less than those determined in the field due to the fact that small cores may not sample fractures or joints [7]. Laboratory results can be a factor of 10 lower than values of permeabilities experienced in the field. It is possible that damage to the cores may result upon extraction, and it may be impossible to reproduce the formation stresses in the laboratory. Hence, it is necessary to determine permeability from history matching production data or from one of the following pressure transient tests:

• Drill stem test (DST).
• Slug test.
• Injection falloff tests (IFT).
– Tank test.
– Below fracture pressure injection falloff test (BFP-IFT).
– Diagnostic fracture injection test (DFIT).
• Pressure buildup test (PBU).
• Multi-well interference test.

The drill-stem test is not the most commonly applied pressure transient test in coals because of safety issues, higher costs, and short radius of investigation. Slug test which is relatively simple to perform with a minimum requirement for equipment and a foolproof operating procedure has the disadvantage that penetration distance into the formation may not be long enough. In the CBM process, a short radius of investigation which may occur in slug test may not incorporate important fractures contributing to formation permeability. For the tank test method, the main advantage is that it is carried out under single-phase testing conditions and therefore eliminates the need for relative permeability curves. It can therefore be used on both pre- and post-stimulated coal-seams with comparatively low cost. The main drawbacks however is that a small breakdown treatment is essential to establish communication between the wellbore and the coal. Also the radius of investigation is small as it is limited to the created water bank and as a result of this a relatively long injection period is required to create a sufficiently large water bank before the falloff data is affected by two-phase flow. If radial/pseudo-radial flow was observed during shut-in, a "unique" solution for pore pressure and permeability can be obtained. If a fracture is created during injection, the falloff data cannot be analyzed using conventional leakoff analysis techniques.

It is evident also that the deeper the reservoir the higher the gas content resulting from the high pressures. Also according to the Langmuir Isotherms of coal, more gas can be adsorbed at higher pressures. The deep coals condition also promotes the maturation process in its generation of methane and progression in rank. Additionally the higher formation pressure associated with deep coals would be an advantage as a driving force for gas production. In these regards, deep coals have the potential of being better producers.

However, the primary problem of the deeper coals is a decrease in permeability with increase in depth. Reference [8]has provided a correlation of permeability with depth which predicts potential problems in producing CBM wells.

Moreover, when pressure declines in coal seams as a consequence of production of water and gas, changes in permeability are as a result of three mechanisms, these are Klinkenberg effect, matrix shrinkage and effective stress. Two of these mechanisms increase permeability and the third reduces permeability.

The Klinkenberg effect increases effective permeability of methane at low pressures [9]. The gas flow through the natural fractures in coal or cleats is described by the Darcy's law of fluid flow. This law includes the assumption that the layer of gas closest to the fracture walls is stagnant and does not move. In coal reservoirs however, as well as conventional sandstone reservoirs, slippage of the adjacent layer does occur at low pressures to give a higher flow-rate than would be calculated by Darcy's law, this phenomenon is described as the Klinkenberg's effect. In the coal seams, pressures are likely to be lower than what is obtained in conventional sandstone reservoirs, especially as production approaches near its abandonment, hence making the phenomenon more significant.

The coal matrix shrinks as gases desorb, which causes an enlargement of the adjacent cleat spacing[4]. This shrinkage increases with adsorbate affinity for the coal. An example is CO_2 which has stronger affinity of the coal than methane and therefore the effect is greater for desorption of CO_2 than for methane. The cumulative shrinkage from the methane desorption is greater near the end of the well life for two reasons. First, at this point on the Langmuir isotherm, more methane is desorbed for a unit pressure decrease, so the greatest rate of matrix shrinkage. Second, most of the methane has been desorbed, and most of the matrix contraction has occurred.

The adsorption of methane in capillaries of a diameter equal to few molecular diameters of the gas which occur in multi-layers of adsorbate is formed as a result of the overlapping energy fields from the surrounding walls. The stacking of these molecules in the confined space exerts a high pressure upon the pore walls of the coal and expands them outwardly. Upon desorption, the walls contract [10]. Hence shrinkage with desorption increases the production rate of methane through enhancement of permeability by widening the cleat apertures.

Water composition as permeability indicator is another interesting feature in the permeability of coal-seams from the ion composition of its formation waters is been reported in San Juan basin. In one of the fields, the fruitland formation, a high concentration of bicarbonate ion (HCO_3^-) in coal seam waters is a significant indicator of favourable permeability, while high concentration of chloride ion (Cl^-) imply stagnant waters of insignificant meteoric recharge[8].

When meteoric waters access the coalbeds, waters of permeable coals may be high in the bicarbonate ion and low in the chloride ions that are swept away. This particular feature is evident at high elevations of the northwestern part of the San Juan basin [11].

To determine the productivity index of a CBM well it is necessary to evaluate accurately the effective permeability of methane in the reservoir at all production stages. Initially, it is expected that the cleats are fully occupied by formation waters. At this point, in which only one phase is present, an injection falloff test can determine the absolute permeability. After the peak gas production rate is reached, the formation water in the coal slowly tends towards irreducible water, and the production rate of the water eventually should become small. As [5]observed, this terminal condition approaching single phase gas flow may last for a long time and can be used to estimate the effective permeability of the gas.
In the multiphase period, however, effective gas permeability is very sensitive to water content of the cleats. As water is extracted to start gas desorption, the water relative permeability decreases rapidly until the immobile water concentration is reached. Conversely, the relative permeability of the gas increases rapidly with increase in the saturation of cleat's water content as it wanes. The relative permeability of gas is the ratio of effective permeability of the gas to the absolute permeability.

$$K_{rg} = \frac{K_g}{K} \qquad 1$$

Where
krg= relative permeability to gas
kg= effective gas permeability
k = absolute permeability as defined by Darcy's law
It is evident that accurate experimental data are not easily obtained for relative permeability. Also, apart from difficulties in establishing experimental conditions, the difficulty associated with determining gas/water relative permeabilities of coal in the laboratory results from the lack of representivity of the seam fracture network by a small core portion. Also, any gravity separation of water/gas in the seam in the field improves the effective permeability of gas over that measured in a small core.

A history match of computer simulations was performed on methane production from the Cedar Hill field of the San Juan basin [12].As seen in Fig. 2.1, the relative permeability of gas must increase much more abruptly with water reduction than similar laboratory data would indicate to match actual production of gas. The observed difference translates into a better production rate of gas in the field than would be predicted from experiments carried out in the laboratory on data of relative permeability.

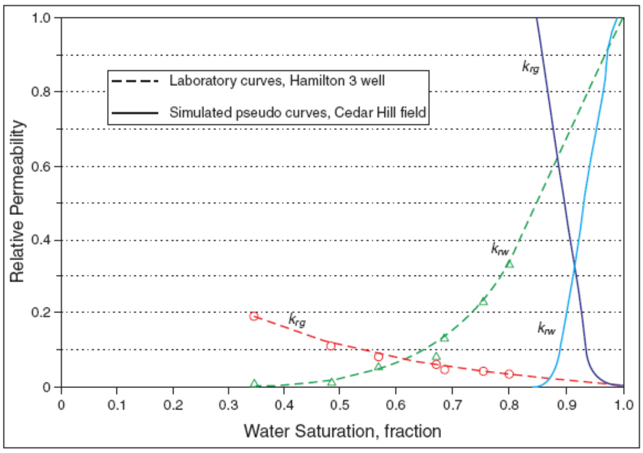

Fig 2-1 Determining Relative Permeabilities from San Juan Basin [18]

2.6 POROSITY

Coal has a dual porosity system. Macropores are the spaces within the cleat system and other natural fractures essential for the transport of water and methane through seams but relatively of less magnitude for storage of methane gas. This storage pore provided by the cleats and other natural fractures contains in addition to the free gas also formation water and methane solution gas, but this provides the primary storage site for formation water in this type of reservoir. It can also have a direct impact on the operating costs of handling and disposition of reservoir formation water produced. Only about 10% of the total gas comes from the free and solution gas found in these macropores [10]. The porosity of the macropores of the cleat system is thought to range between 1-5%
The second type of porosity found in CBM reservoirs is known as micropores which refer to the capillaries and cavities of molecular dimensions in the coal matrix that are essential for gas storage in the adsorbed state. Most of the gas in CBM reservoirs occurs in this type of pore in the form of adsorbed gas on the solid surface of the coal matrix. Reference [10] estimates that 98% of the methane gas in Coal seams is typically adsorbed and stored in the micropores. Although coal porosity may be only 2% in the cleat system, it may have a storage capacity for methane in the micropores equivalent to that of 20% porosity sandstone of 100% gas saturation at the same depth.

2.7 FISSURED RESERVOIR MODEL FOR CBM WELLS

In fissured reservoir, the fissured network and the matrix block react at a different time, and the pressure response deviates from the standard homogenous behavior.
The Pressure profile for such reservoirs is indicated in figure (2-2).

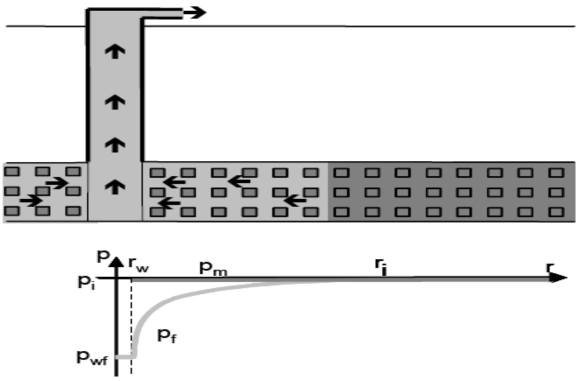

Fig 2-2 Double porosity behaviour and Pressure distribution for Fissured system in a Homogenous Regime.

First, the matrix block production is negligible. The fissure system homogenous behavior is seen. When the matrix block start to produce into the fissures, the pressure deviates from the homogenous behavior and follow a transition regime as shown in figure (2-3).

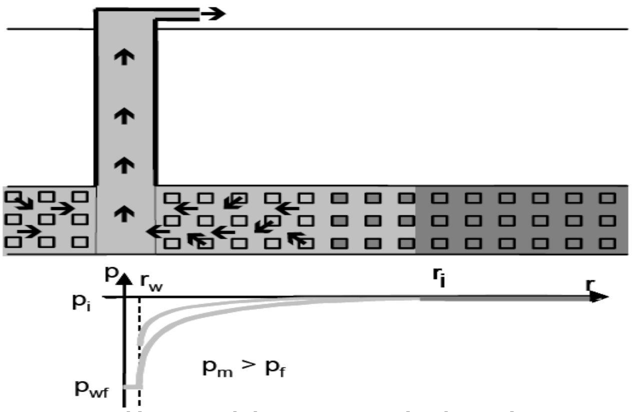

Fig 2-3 Double porosity behaviour pressure distribution during Transition regime

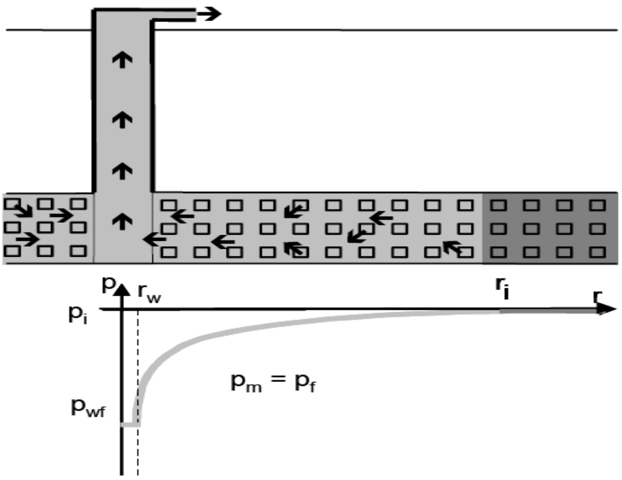

Fig 2-4Double porosity behaviour and pressure distribution during total system homogenous regime (fissures + matrix)

When the pressure equalizes between the fissure and the matrix blocks, the homogenous behavior of the total system (i.e. the fissure and the matrix) is reached this is illustrated in figure (2-4).

In this system, the fluid flows through the fissure network only and the radial permeability of the matrix system does not contribute to the mobility (k_m*=0).*

The product of permeability and thickness *Kh* which is estimated by the interpretation is used to define an equivalent bulk permeability of the fissure system, over the entire thickness *h*:

$$kh = k_f h_f$$

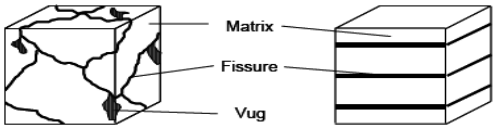

Fig 2-5 example of double porosity reservoir, fissured and multiple-layer formations

The porosity in this system is of two types; the vuggy and the fissure porosity. The vug do not contribute to flow as illustrated in fig (2-5) and therefore porosity is defined with respect to the total volume of the fissure.Thus the porosities are defined as follows:

$\emptyset_m$ is the ratio of the pore volume in the matrix to the total volume of the fissures of the matrix

$\emptyset_f$ is the ratio of the pore volume in the fissure to the total volume of the fissures of the matrix

V_m is the ratio of the total volume of the matrix to the total volume of the reservoir

V_f Is the ratio of the total volume of the fissure to the total volume of the reservoir.

$$V_m + V_f = 1 \qquad 2$$

The porosity of the system is given by

$$\emptyset = \emptyset_m V_m + \emptyset_f V_f \qquad 3$$

In practice however, $\emptyset_f$ and V_m are close to 1. Therefore the average porosity in the above equation can be simplified as:

$$\emptyset = \emptyset_m + V_f \qquad 4$$

The storativity ratio ω is given by

$$\omega = \frac{(\emptyset V C_t)_f}{(\emptyset V C_t)_f + (\emptyset V C_t)_m} = \frac{(\emptyset V C_t)_f}{(\emptyset V C_t)_{f+m}} \qquad 5$$

The interporosity flow parameter λ is defined as:

$$\lambda = \alpha r_w^2 \frac{K_m}{K_f} \qquad 6$$

Where, α is a parameter related to the geometry of the fissure network, defined with the number *n* of families of fissure planes. For n=1 they are slabs and for n=3, the matrix blocks are cubes or spheres. α Is given by the equation (7)

$$\alpha = \frac{n(n+2)}{r_m^2} \qquad 7$$

Where $r_m$is the characteristic size of the matrix block and defined as the ratio of the volume V of the matrix blocks to the surface area of the blocks: $r_m = nV/A$ 8

When a skin effect S_m is present at the surface of the matrix blocks, the matrix to fissure flow is called restricted interporosity flow.

$$S_m = \frac{K_m}{r_m}\frac{h_d}{K_d} \qquad 9$$

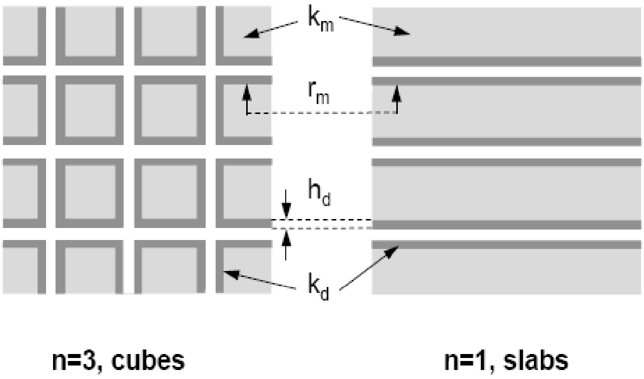

Fig 2-6 Matrix skin for slab and sphere matrix blocks

The effective interporosity flow parameter λ_{eff} is provided by the analysis of pseudo-steady state interporosity flow otherwise known as the restricted interporosity flow. This parameter is independent of the matrix block permeability K_m.

$$\lambda_{eff} = n\frac{r_w^2}{r_m h_d}\frac{K_d}{K_f} \qquad 10$$

Figure (2-6) shows how these parameters are obtained from the system.

3. METHODOLOGY

The methodology for this work involves the comparison of well-test interpretation of some conventional oil and gas reservoirs with what obtains in CBM reservoirs. The approach will determine some of the anomalies observed in CBM well-testing and try to interpret the reasons for the anomaly. Classical case of drill-stem test in Queensland will be used to identify such anomalies.

3.1 PRESSURE TRANSIENT ANALYSIS.

Reference [13] noted that the production of gas reservoirs is analogous to an extended drawdown test, which is most commonly associated with production in which the rate is variable. Using the superposition principle they showed, the multiple rate data can be transformed into an equivalent single-rate draw-down test, and then analyzed using conventional techniques. To analyze flow regimes therefore, derivative curves can be used as is used in conventional pressure analysis. The extended draw-down in this principle uses the Odeh-Jones [13] equation for a multi-rate, drawdown test (in the infinite acting flow regime) assuming the fluid is compressible.

$$\frac{m(P_i)-m(P_{wf})}{q_n} = m\sum_{j=1}^{n}\frac{(q_j-q_{j-1})}{q_n}\log\left(t_n-t_{j-1}\right) + m\bar{S} \qquad 11$$

Where

$$\bar{S} = \log\left(\frac{k}{\emptyset\mu_{gi}c_{ti}r_w^2}\right) - 3.23 + 0.869s \qquad 12$$

And equivalent time (t_e) may be defined as

$$t_e = \sum_{j=1}^{n}\frac{(q_j-q_{j-1})}{q_n}\log\left(t_n-t_{j-1}\right) \qquad 13$$

A Cartesian plot with the left-hand-side of equation (11) (rate normalized pseudopressure drop) versus t_e will yield a straight line from which effective permeability and skin can be estimated (when the flow is in infinite acting regime). The skin and permeability can be estimated from the intercept and slope respectively. One of the conditions for the application of equation (11) is that a pseudo-radial flow regime must be identified. The traditional well-testing use of log-log plots in combination with derivative curves can be used for the purpose of identifying flow regimes.

The derivative equation is given as follows

$$\frac{\Delta P(q)}{\log(\Delta t)} = \frac{\Delta\left(\frac{m(P_i)-m(P_{wf})}{q_n}\right)}{\Delta t_e} \qquad 14$$

As in conventional derivative analysis, functions for smoothing may be applied to improve interpretation. However, ideally the derivative curves should enable the identification of various flow regimes such as zero slope for infinite acting, ½ slope for linear flow and unit slope for boundary dominated flow.
Another useful parameter that can be derived from standard pressure transient test is radius of investigation. The calculation which is for infinite acting flow is as follows:

$$r_i = \sqrt{\frac{kt}{948\emptyset\mu_{gi}c_{tu}}} \qquad 15$$

This calculation can be used to estimate how far a transient has traveled at a particular time during production and is particularly useful for estimating drainage radius, corresponding to the onset of boundary-dominated flow.

3.2 STRESS DEPENDENCE OF PERMEABILITY AND POROSITY

One major difference between conventional oil and gas reservoirs and CBM reservoirs is the issue of stress dependant permeability and porosity (SDPP). This has been addressed by [14] where it was shown that the bulk permeability of the natural fracture system or cleat is stress dependent and changes in pore pressure will alter the effective stress resulting from the grain pressure.

The slug test has been much used to analyze coal-bed methane where it is important to determine the bulk permeability of the connected fissure system. Reference [15] proposed an equation to define a normalized pseudopressure of the form:

$$\psi(P) = \frac{1-\phi_i}{K_i}\int_{P_b}^{P}\frac{K(\acute{P})}{1-\phi(\acute{P})}d\acute{P} \qquad 16$$

Or

$$\psi(P) = \frac{1-\phi_i\mu_{wi}}{\rho_{wi}K_i}\int_{P_b}^{P}\frac{\rho_w K(\acute{P})}{(1-\phi(\acute{P}))\mu_w}d\acute{P} \qquad 17$$

In this equation it is presumed that only one phase is present during the testing period (water phase). Using this type of transformation, the superposition principle is valid. The concept of pseudopressure drives from an analysis of steady-state, radial flow described by D'Arcy's equation in the form:

$$\frac{q}{A} = \frac{q}{2\pi r\,h(p)} = u_r = \frac{K(P)}{\mu}\frac{dp}{dr} \qquad 18$$

In this equation the permeability is a function of pore pressure and therefore stress dependence can be accounted for. The effect of compaction on the formation thickness is predicted through a pressure dependence of the formation thickness denoted by h(p).

$$h_{eff} = h(P) = \frac{h(P_i)[1-\phi(P_i)]}{[1-\phi(P)]} \qquad 19$$

Separating the variables in equation (16) then using equation 19 and substituting for h, we obtain;

$$\frac{dr}{r} = \frac{2\pi h(P_i)[1-\phi(P_i)]}{q\mu}\frac{K(P)}{[1-\phi(P)]}dP \qquad 20$$

Integrating equation 20 in the limits r_e and r_w and P_e and$P_b$we obtain,

$$\int_{r_w}^{r_e}\frac{dr}{r} = \frac{2\pi h(P_i)[1-\phi(P_i)]}{q\mu}\int_{P_w}^{P_e}\frac{K(P)}{[1-\phi(P)]}dP \qquad 21$$

$$\ln\frac{r_e}{r_w} = \frac{2\pi h(P_i)[1-\phi(P_i)]}{q\mu}\int_{P_w}^{P_e}\frac{K(P)}{[1-\phi(P)]}dP \qquad 22$$

Hence from the definition of normalized pseudopressure, the above integral part can be as

$$\int_{P_w}^{P_e}\frac{K(\acute{P})}{[1-\phi(\acute{P})]}dP = \int_{P_b}^{P_e}\frac{K(\acute{P})}{[1-\phi(\acute{P})]}dP - \int_{P_w}^{P_b}\frac{K(\acute{P})}{[1-\phi(\acute{P})]}dP \qquad 23$$

The steady state radial inflow equation can therefore be written in the form:

$$\ln\frac{r_e}{r_w} = \frac{2\pi K_i h_i}{q\mu}\{\Psi(\overline{P}) - \Psi(P_w)\} \qquad 24$$

This can be converted to semi steady state (SSS) conditions with skin effect as follows:

$$\ln\frac{r_e}{r_w} - \frac{3}{4} + S = \frac{2\pi K_i h_i}{q\mu}\{\Psi(\overline{P}) - \Psi(P_w)\} \qquad 25$$

Or

$$q = \frac{2\pi K_i h_i}{\mu\left(\ln\frac{r_e}{r_w}-\frac{3}{4}+S\right)}\{\Psi(\overline{P}) - \Psi(P_w)\} \qquad 26$$

Supposing a stress dependent pseudopressure function has been computed the well deliverability curve can be determined.

3.3 PALMER AND MANSOORI MODEL FOR SDPP

In gas well-testing, pseudo-pressure [m(p)] allows interpretation for K and S in the usual way on log-log or semi-log plots, this is not obtainable in the case of CBM where porosity and permeability are stress dependent (SDPP). It is therefore necessary to determine rock mechanical parameters such as the one used by Palmer and Mansoori (E, v, n) in order to use the pseudopressure concept. This is an anomaly with regards to conventional well-testing gas wells.
Their investigation proposed the following model:

$$\frac{\phi}{\phi_i} = 1 + \frac{(P-P_i)}{\phi_i M} \qquad 27$$

$$\frac{K}{K_i} = \left(\frac{\phi}{\phi_i}\right)^3 \qquad 28$$

Where: $M = E\frac{1-V}{(1+V)(1-2V)}$ constrained axial modulus 29

And E= Young modulus and V= Poisson ratio
Equation (25) relates porosity and pressure based on rock mechanics properties while equation (26) relates permeability dependence on porosity. In the field of coal seams, only the fracture system (no matrix) is present. The model is described based on linear elasticity and will therefore not handle pore collapse (plastic deformation). Also observed changes in effective formation height is secondary to change in permeability which is dominant. In the foregoing treatment, the basic rock properties are evaluated at the initial reservoir pressure, p_i. In the event that the real initial reservoir pressure is known-in a buildup or fall-off analysis for example, then the quantity P_i will be better referenced simply as P_{ref}. this is only a convenience at which formation properties can be computed.
The fundamental test interpretation model is the radial flow using the finite wellbore radius (FWBR) formulation written as $P_D^{rw}(t_D)$ which will take into account the effect of negative skin if it is present. This is evaluated using the Stehfest algorithm. The definition of dimensionless pseudopressure is:

$$P_D = \frac{(\psi(P_i)-\psi(P_w))2\pi Kh}{\acute{\alpha}_P \acute{q}_s B\mu} \qquad 30$$

Where $\acute{\alpha}_P$is a conversion factor. Hence the pressure record is converted to pseudopressure using the transform and then the pseudopressure results are converted back to actual pressures.

If the skin effect is zero or positive then the line source solution can be approximated.

$$P_D = \frac{(\psi(P_i)-\psi(P_w))2\pi K h}{\acute{\alpha}_P\, \acute{q}_s B\mu} = \frac{1}{2}\ln\left(\frac{4t_D}{\gamma}\right) + S \qquad 31$$

Here S represents the true mechanical skin factor of the well. In the first instance, the dimensionless time, t_D, entering $P_D^{rw}(t_D)$ or the line source form, is based on properties at the at the initial reservoir pressure, P_i, thus

$$t_D = \frac{\alpha_t K(P_i) t}{\phi(P_i)\mu C_t r_w^2} \qquad 32$$

The rock compressibility, C_f, entering total compressibility C_t is as well calculated at initial reservoir pressure, P_i. A relationship exists between E and C_f and is given by $Cf = 1/((2E\phi i\,))$ for coal beds.

To generate Stress Dependent Porosity and Permeability (SDPP) pseudopressure function, you initially input rock mechanics parameters (E, v, n) into Palmer and Mansoori model and generate pseudopressure function by quadrature integration. This is illustrated schematically in figure(3-1)

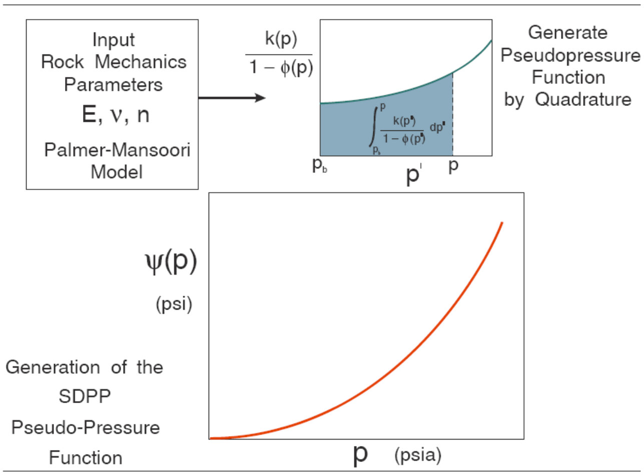

Fig 3-1 Generation of SDPP Pseudopressure function

4. RESULTS AND ANALYSIS

The results used for this research were obtained for a slug test of a CBM well in Queensland as reported by [14].

The result shows a test overview of a Queensland CBM test with the log-log diagnostic for the build-up test carried out and presented in the figures (4-1) to (4-5). The log-log analysis shows the middle time region which is used to determine the value of the cleat system bulk permeability.

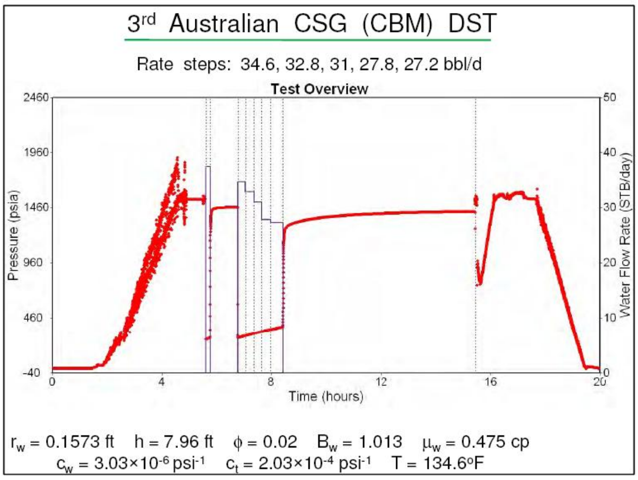

Fig 4-1 A test overview of the CBM DST on Queensland field

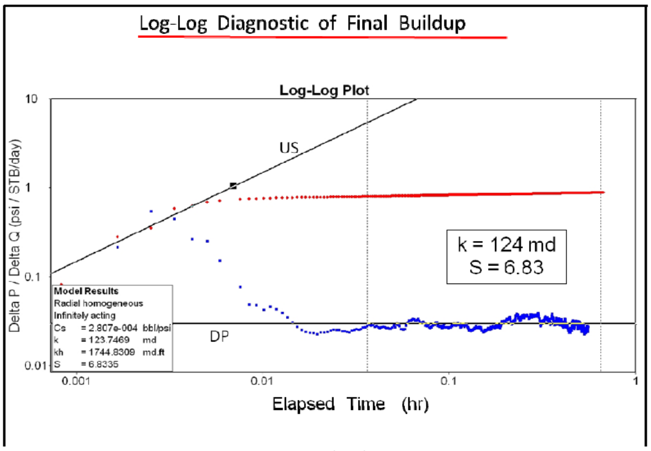

Fig 4-2 log-log plot for final build-up test

Figure (4-3) also shows a log-log analysis of final build-up of a well in Queensland field, where it is interpreted based on 90[0] intersecting fault. This is unlikely to be faults but rather it is due to some small scale features in the coal seam and it can also be observed to have an unusually large well-bore storage which can be described as an anomaly in the well-testing. This can be related to opening and closure effect of the fracture system as in [14].

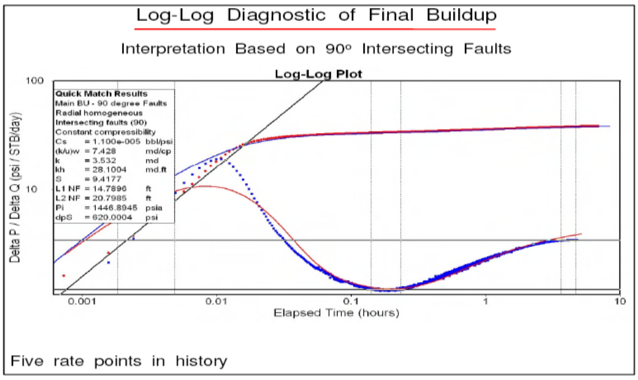

Fig 4-3 log-log analysis of final build-up for a CBM well

4.1 SKIN EFFECT IN CBM WELLS

In many pressure transient test analysis carried on CBM wells, a large value of the skin factor, S, is observed. This unusually large value raises question as to the significance and origin of this anomaly. But the first issue to consider in this situation is the fact that coal seams are naturally fractured reservoirs and it has been shown by [14] that the ideal value for skin in a fractured system is negative.

Reference [14] that the skin is composed of the true skin S and rate dependent skin factor due to stress effect, S_σ.

$$S_a = S + S_\sigma \qquad 31$$

The decomposition of this observed apparent skin S_a into damage and rate dependent skin factor is difficult since the components are not additive, arithmetically. This is illustrated in the figure (4-4) which is generated by running the SDPP model which implements equation (32) and the superposition principle to model stress dependent situation. The synthetic data generated by the SDPP is then analyzed using conventional analysis technique in terms of pressure, to determine the total apparent skin, S_a, for a given true mechanical skin, S.

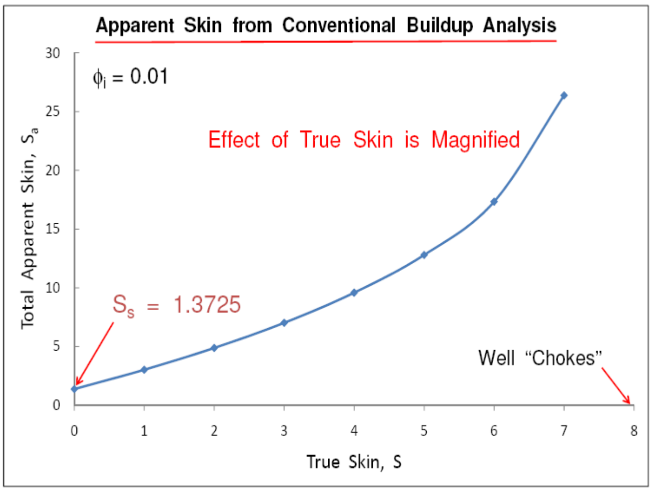

Fig 4-4 Non additive nature of components of Apparent skin in pressure transient test of CBM

However, if the Palmer-Mansoori model [16] parameters for the SDPP are known the plot above can be prepared, for the specific set of rock mechanical properties which will allow measured apparent skin (S_a) to be decomposed into its components.

In the situation where bottomhole flowing pressure falls below the methane critical desorption pressure (CDP), then the development of free gas saturation near the wellbore will cause an increased pressure drop in the near wellbore region resulting in an increase in the apparent skin S_a observed in the analysis.

The CDP has been shown to depend on the gas content of the coal and the Langmuir isotherm which is used for the gas recovery calculation. This phenomenon of going below CDP is termed *"gas blocking"* in conventional oil wells analysis. If the gas pressure reaches the CDP it has reported that the permeability of water reduces approximately by a factor of three. This effect on well deliverability can be modeled by a two-phase (water and methane), steady-state pseudopressure using up scaled relative permeability curves. Figure (4-5) indicates the determination of gas block skin factor using Hawkins equation [14].

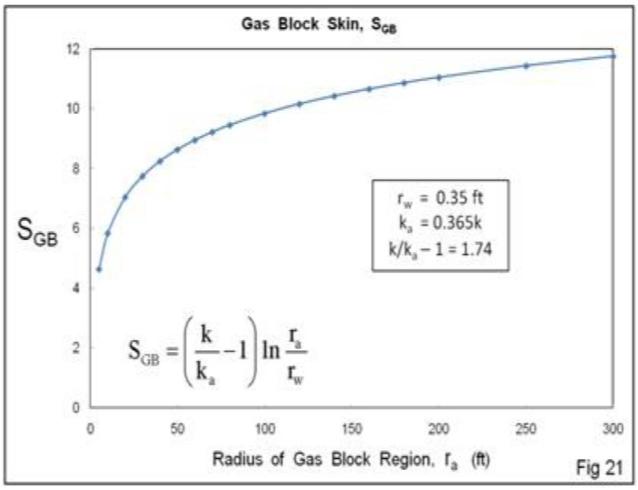

Fig 4-5 Determination of gas blocking skin contribution

5.0 CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS

Several techniques used in well-testing conventional oil and gas reservoirs and the universal method of analysis and interpretation can be applied to CBM reservoir with some modification. This is as a result of the nature of the coal rock mechanical properties and the geological controls on its deposition.

It can be concluded that some of the anomalous features of CBM wells cannot be interpreted by the derivative analysis on conventional DST techniques data. Some of the evidence determined indirectly through the presence of anomalous wellbore storage and the high Skin factor from:

Stress dependence of permeability and porosity which is determine by the superposition principle using pseudopressure technique and Palmer and Mansoori model

The large value total apparent skin observed in CBM well-testing is a result of the rate dependent skin contribution due to stress effect.

The decomposition of the apparent skin into its component (damaged and stress dependent) is difficult since they are not arithmetically additive and the interpretation of the apparent skin will depend on whether the Palmer-Mansoori parameters are known.

The apparent skin value is magnified when the critical desorption pressure is reached due to the formation of gas saturation around the wellbore.

5.2 RECOMMENDATION

The time frame for this research was obviously insufficient to investigate all the effects desired and therefore the following recommendations were made for future work.

The investigation carried out only considered a few data for the analysis which might not be sufficient to reveal other inherent features.

In cases where the rock mechanical properties such as E, V and n are not known, for use in Palmer-Mansoori model, a different approach should be innovated.
Pressure transient analysis should also be investigated at pressures below the critical desorption pressure (CDP)

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