PROCEEDINGS, Nineteenth Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, January 18-20, 1994
SGP-TR-147

MEASUREMENT OF INJECTIVITY INDEXES IN GEOTHERMAL WELLS WITH TWO PERMEABLE ZONES

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ABSTRACT

Injectivity tests in wells with two permeable zones and internal flow is analyzed in order to include the usually severe thermal transient effects. A theoretical analysis is performed and a method devised to obtain information from the thermal transient, provided that temperature is measured simultaneously with pressure. The technique is illustrated with two real tests performed at Miravalles, Costa Rica. It allows to estimate total injectivity index as well as the injectivity index of each one of the two zones separately. Correct position of measuring tools and nature of spontaneous internal flow is also discussed.

INTRODUCTION

Miravalles geothermal field in Costa Rica is a water dominated reservoir whose permeability is attributed to fracture systems embedded in an otherwise low permeability geologic formation. Permeable zones are usually localized and many wells present two or more zones between which spontaneous flow occurs. To characterize these wells with respect to their productivity potential previously to production tests, two parameters are looked for, the injectivity index and hydraulic transmissivity from pressure transient injection tests.

The injectivity index of a well is a measurement related to permeability, but considered poorer in quality when compared to transmissivity obtained from pressure transient tests. Wells in fractured systems, however, that intercept only a few fractures often deviate from conventional models for fractured systems [3]. During pressure transient tests, systems of fractures with only a few feeding points to a well may behave as networks with fractal geometry [1]. This type of systems may approach asymptotically a constant pressure when subject to injection at constant flow rate, even when they are still behaving as systems of infinite size [1]. This fact corroborated numerically [1] and observed in real tests [2] [3], gives new reliability to the old injectivity index measurement.

Injectivity indexes have been proven reliable in Miravalles to assess productivity of wells and also to predict performance of injector wells. Our experience, as well as the experience in other geothermal fields [5], shows that this simple measurement relates closely to the productivity index of wells. Injectivity is also easy to obtain during drilling and just after completion of new wells.

Pressure transient analysis of injection tests in geothermal wells, such as fall-offs and step rate tests, may yield hydraulic transmissivity and a product of storativity-skin factor in wells of low permeability [4]. In wells of high permeability, such as many wells at Miravalles, thermal transients caused by different temperature of the injected fluid, spontaneous internal flow and thermal recovery of wells usually dominate over the comparatively small pressure transient response and the interpretation becomes too complicated [5].

To minimize thermal effects it is recommended to locate the pressure tool in the main permeable zone [5]. However, there is no recipe for wells with more than one permeable zone and none of them appearing as clearly dominant. In some wells with two zones at Miravalles, it was attempted to locate the tool in the upper zone and later in the lower zone, obtaining severe thermal effects in both cases. This causes the determination of the hydraulic transmissivity *kh* from injection tests to be quite ambiguous. Thus, we have to rely only on injectivity tests.

In these tests, the normal practice is to eliminate thermal effects by making a massive injection to cool down the well before the test [4], and then proceed with the test itself. In practice, however, it is often difficult to supply the usually large amounts of water required. Drilling rig time expense is also a concern.

This paper describes the theory and practical application of a simple approach to obtain good values of injectivity indexes in wells with two permeable zones previously identified. It is argued that information from thermal transients can be used to characterize each one of two permeable zones separately or, at least, improve interpretation of tests affected by severe thermal effects.

THEORETICAL MODEL AND ASSUMPTIONS

It is assumed that we have a well with two permeable zones with injectivity index ii_{up} for the upper zone and ii_{lo} for the lower zone. It is also assumed that the indexes remain constant to changes in flow rate and temperature of the circulating fluid.

For short tests, such as the ones we perform at Miravalles, the extension of the cold spot caused by injection is small, therefore, properties of reservoir fluid, not injected fluid, are the ones that dominate the behavior [4][6]. The assumption of no change of the injectivity with changes in temperature of the injected fluid is, thus, justified.

The two zones are separated by a distance H and the upper zone has an overpressure SP with respect to the lower zone (this overpressure could also be an underpressure). Reservoir pressure in the upper zone is p^*_{up} and the reservoir is initially at the same temperature T^*.

SPONTANEOUS FLOW WITHOUT INJECTION

Based on the initial conditions it is possible to establish the reservoir pressure in the lower zone p^*_{lo} as

$$p^*_{lo}=p^*_{up}-SP+\rho_{T^*}gH \qquad \textbf{(1)}$$

where ρ_{T^*} is the density of the reservoir fluid at its initial temperature T^*.

Once the well has been drilled and the two permeable zones are communicated, spontaneous flow is established. Assuming isothermal temperature profile, the flow rate produced by one zone is the same one accepted by the other and we have

$$ii_{up}(p^*_{up}-p_{up})=-ii_{lo}(p^*_{lo}-p_{lo}) \qquad \textbf{(2)}$$

Considering also negligible friction pressure losses in the well, pressure at the lower zone can be calculated from the pressure in the well at the upper zone as $p_{up}+\rho gH$, where ρ is the density of the fluid in the well that changes as the well recovers thermally. An expression for pressure at the upper zone of the well at a given time can be written as

$$p_{up}=p^*_{up}-\frac{ii_{lo}}{ii_{up}+ii_{lo}}(SP+\Delta\rho gH) \qquad \textbf{(3)}$$

where $\Delta\rho=\rho-\rho_{T^*}$.

According to equation (3), in wells with spontaneous flow, the "static" pressure does not reflect the reservoir pressure even if measured in front of one of the permeable zones.

The circulating flow rate can then be calculated as

$$Q_{up}=-Q_{lo}=\frac{ii_{up}ii_{lo}}{ii_{up}+ii_{lo}}(SP+\Delta\rho gH) \qquad \textbf{(4)}$$

Even when $SP=0$ there will be flow between the two zones. Thus, spontaneous internal flow may be caused only by the pressure gradient created by changes in density due to cooling of the well. If this is the case, flow should stop once the well reaches thermal equilibrium with the formation. A fundamental characteristic of this type of flow is that its direction must be downwards (down-flow) because it is driven by gravity forces.

FLUID INJECTION

To consider injection of fluid, the mass balance equation is stated again but including the injected flow rate Q, in this case well pressure in the upper zone is given by

$$p_{up}=p^*_{up}-\frac{ii_{lo}}{ii_{up}+ii_{lo}}(SP+\Delta\rho gH)+\frac{Q}{ii_{up}+ii_{lo}} \qquad \textbf{(5)}$$

The corresponding expression for produced (positive) or accepted (negative) flow rate in the upper zone is

$$Q_{up}=\frac{ii_{up}}{ii_{up}+ii_{lo}}(ii_{lo}(SP+\Delta\rho gH)-Q) \quad \textbf{(6)}$$

Flow rate from the formation to the well in the upper zone Q_{up} can be zero when the injected flow rate Q is equal to $k_{lo}(SP+\Delta\rho gH)$. If, however, injected flow rate is less than that, there will be production of fluid from the upper zone, otherwise, the upper zone will accept injected fluid.

The lower zone, on the other hand, will always accept fluid at a flow rate given by

$$Q_{lo}=-\frac{ii_{lo}}{ii_{up}+ii_{lo}}(ii_{up}(SP+\Delta\rho gH)+Q) \quad \textbf{(7)}$$

All previous equations are valid at a given time because it is assumed that temperature is changing continuously. To incorporate the variable time in the analysis we discretize the process in injection stages as follows.

Let us assume that there are two stages of injection at flow rates Q_a and Q_b that could be equal. It is also assumed that temperature of the well between the two zones is such that the respective densities are ρ_a and ρ_b. It can be shown that the pressure change Δp measured in the upper zone is related to the change in flow rate $\Delta Q=Q_b-Q_a$ and to the change in density $\Delta\rho=\rho_b-\rho_a$ as follows

$$\Delta p_{up}=\frac{\Delta Q}{ii_{up}+ii_{lo}}-\frac{ii_{lo}}{ii_{up}+ii_{lo}}gH\Delta\rho \quad \textbf{(8)}$$

If the second flow rate Q_b is larger than the first one Q_a, the change in flow rate will be positive as well as the density change, therefore, if there is an important difference between temperature between both stages, the pressure change would be **underestimated** if the tool is located at the upper zone. If the injectivity index is calculated in the conventional way as $ii=\frac{\Delta Q}{\Delta p}$, it will be overestimated. Notice the possibility of having negative pressure changes when the lower zone has good injectivity with respect to the upper zone and when the temperature changes are large.

The pressure change in the lower zone is given by

$$\Delta p_{lo}=\frac{\Delta Q}{ii_{up}+ii_{lo}}+\frac{ii_{up}}{ii_{up}+ii_{lo}}gH\Delta\rho \quad \textbf{(9)}$$

According to equations (8) and (9), thermal effects on the total pressure change depend on the relative magnitude of the injectivity of the two zones. This relationship constitutes the basis for extracting information of the two zones separately.

In general, when the pressure change at a depth X $(0 < X < H)$ below the upper zone is considered, we have

$$\Delta p=\frac{\Delta Q}{ii_{up}+ii_{lo}}+\frac{X(ii_{up}+ii_{lo})-Hii_{lo}}{ii_{up}+ii_{lo}}g\Delta\rho \quad \textbf{(10)}$$

An important result of this expression is that there is a given depth X_0 where measurements are not affected by thermal effects and this depth is given by

$$X_0=H\frac{ii_{lo}}{ii_{up}+ii_{lo}} \quad \textbf{(11)}$$

As expected, this distance approaches zero (upper zone) only when the index of the upper zone is very large with respect to the one of the lower zone and H when the injectivity of the lower zone is very large with respect to the one of the upper zone. In practice, however, this equation is important once the individual injectivity indexes are known because it allows to measure pressure changes without thermal interference, a feature highly desirable in pressure transient tests.

PRACTICAL APPLICATION OF THE MODEL

As mentioned above, before applying the described model for injection test interpretation, it is necessary to know the location of the two permeable zones. We usually do this by means of two temperature profiles of the well. The first one is done without injecting and after several hours of thermal recovery. Immediately after this first profile, injection is started at a flow rate of 15 to 20 liters per second. The second profile is the injecting profile that is made one or two hours after starting injection.

Figure 1 shows this two profiles for well A in Miravalles geothermal field. The "static" profile shows a thermal peak that corresponds to the upper permeable zone. Immediately below, there is a zone with constant temperature in which the spontaneous flow is taking place. The injecting profile shows the location of the upper zone as a small change of gradient but it shows clearly the lower zone. With this information it is possible to conclude that the two zones are separated by a distance close to 550 m and both are accepting injected water.

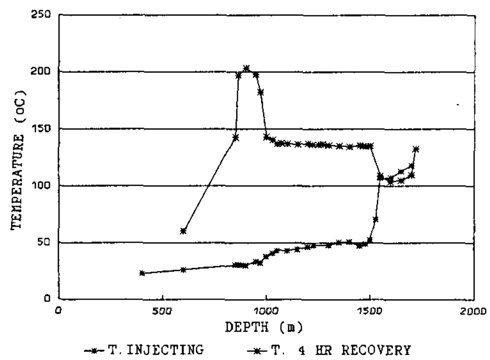

Figure 1. Temperature profiles with and without injection for well A in Miravalles, Costa Rica, showing the location of two permeable zones separated 550 m approximately.

To apply the model to injectivity test interpretation, we use equations (8) and (9) for the increments of pressure that occur between successive times of the test.

Although ΔQ should include wellbore storage effects, these are disregarded because they disappear after short time. On the other hand, $\Delta\rho$ should take into consideration the temperature change in the entire column of fluid between the two zones. It was assumed before, however, that the entire column of fluid has the same temperature equal to the one measured by the tool located inside the internal flow region.

To perform an injectivity test we introduce in the well a tandem of tools to measure pressure and temperature. The tandem must be located the closest possible to the selected permeable zone but always inside the region where the internal flow occurs.

The analysis technique consists of calculating density for each time based on the *corresponding* pressure and temperature. It has to be remembered that the dependence between density of liquid water and pressure is very small. Using consecutive data, changes ΔQ and $\Delta\rho$ are calculated. Even when measured temperature may not correspond to the actual average temperature of the region between permeable zones, the change in temperature and, thus, the change in density is very likely to correspond better to the true change in average density. Using guessed values for ii_{up} and ii_{lo}, the pressure change Δp can be calculated using equation (8) or (9) depending on the location of the tandem of tools.

The theoretical pressure for a given time would be equal to an initial pressure plus the summation of the pressure changes that occur up to that given time. The final step is to adjust the values of the indexes ii_{up} and ii_{lo} to obtain a reasonable match between the measured and calculated pressures. The initial pressure is usually set equal to the one measured by the tool, but it can also be adjusted, keeping the difference below the error associated with the tool for measurement of absolute pressure.

APPLICATION TO ACTUAL CASES

The first case to be analyzed corresponds to an injectivity test in well A at Miravalles. As shown in Figure 1, the permeable zones are separated 550 m. Figure 2 shows the injectivity test performed with the tandem of instruments in the upper zone at 970 m. The temperature curve shows a maximum temperature above 200°C. This indicates that the tool was located a little above the spontaneous flow

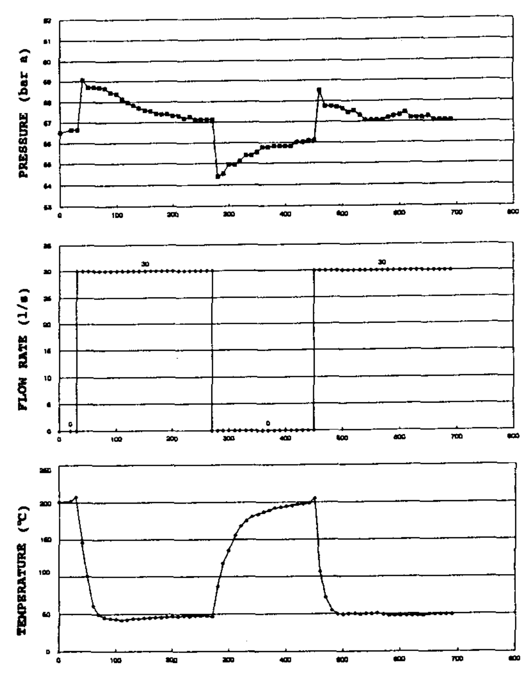

Figure 2. Variation of pressure, flow rate and temperature during injectivity test of well A. Tools located in the upper permeable zone.

region. The "static" profile of Figure 1 shows that the maximum temperature that occurs in this region after four hours of recovery is approximately 140°C. The stage without pumping lasts 3 hours, therefore, the thermal variation that occurs during the injectivity test is linearly corrected to give a maximum temperature of 140°C, keeping the same minimum temperature.

Figure 3 shows the best fit for the pressure curve obtained after manual matching. The index in the upper zone ii_{up} is 2.5 (l/s)/bar, the one of the lower zone ii_{lo} is 5 (l/s)/bar. The total injectivity index of this well is, therefore 7.5 (l/s)/bar.

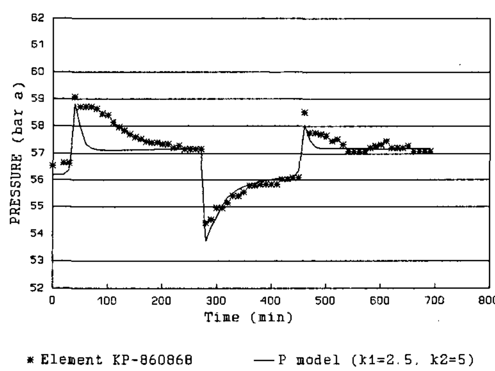

Figure 3. Variation of pressure and corresponding best fit curve for injectivity test of well A.

The match is good except for the first stage of pumping where cooling of the fluid column inside the well occurs slower than that measured by the temperature tool located in the upper zone. The assumption of making the average temperature of the well equal to the one measured by the tool, however, appears to give reasonable results for the following parts of the test.

The second case to be presented corresponds to an injectivity test for well B in Miravalles. This well also has two permeable zones. The first one located in the interval 1000-1100 m and the second one in the interval 1450-1550 m. For this test the tandem of tools was located in the lower zone at 1550 m deep. Figure 4 shows the profiles with and without injection. The profile without injection shows the characteristic length of at least 450 m with constant temperature caused by the spontaneous flow. The injecting profile shows how the assumption of constant temperature during injection for the entire segment between permeable zones is a reasonable one.

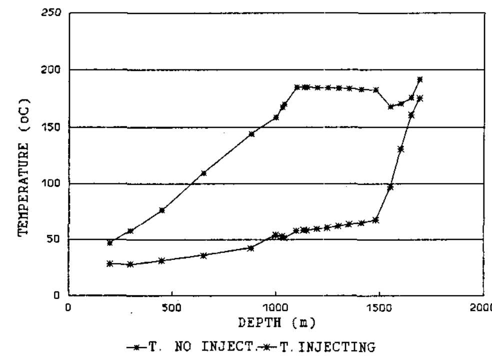

Figure 4. Temperature profiles with and without injection for well B in Miravalles, Costa Rica, showing two permeable zones separated 450 m approximately.

Figure 5 shows the variation of pressure, flow rate and temperature for this test that concluded with a fall-off. Based on the thermal variation shown in Figure 5 and its comparison with the injecting profile of Figure 4, it seems that the tool was located a little below the internal flow region. Therefore, the temperature curve is corrected linearly so that the initial temperature of the graph is equal to the respective temperature in the injecting profile. The minimum temperature remains the same as well as the fall-off part of measurement.

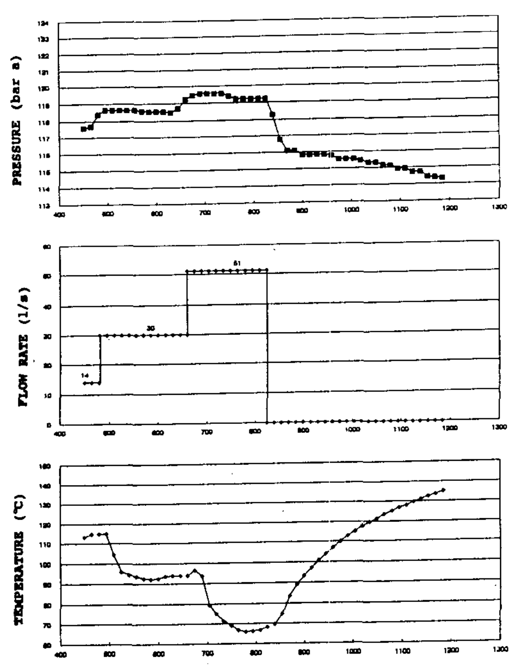

Figure 5. Variation of pressure, flow rate and temperature for injectivity test and fall-off for well B. Measuring tools located in the lower zone.

The slope of the fall-off curve is very large. If this curve is conventionally interpreted with the multiple flow rate pressure transient technique, it would give conductivities of the order of 1 Darcy-m, a value extremely low for this well. Actually, the fall-off part of the test is severely affected by thermal effects and should not be used to determine hydraulic transmissivity ***kh***, nevertheless, it is important to obtain the best fit curve for injectivity indexes as shown below.

Figure 6 shows the measured pressure curve and the theoretical best-fit curve. The match is good even for the fall-off part of the test. The best-fit values for ii_{up} and ii_{lo} are 18 and 1 (l/s)/bar respectively. The shape of the fall-off curve allows to determine that the value of injectivity of the upper zone is much larger than that of the lower zone.

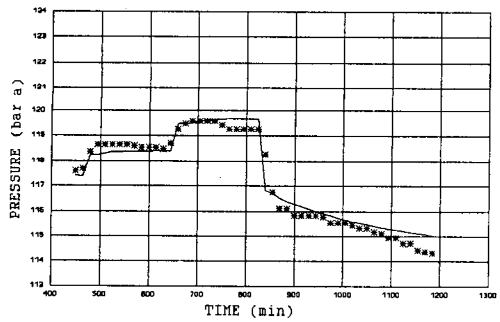

Figure 6. Variation of measured pressure and respective best fit curve for injectivity and fall-off test of well B.

CONCLUSIONS

Spontaneous flow between two permeable zones in a well can be established without the existence of an overpressurized zone. It is only necessary to induce cooling of the well such as the one that occurs during drilling. If the flow is caused by simple cooling, the flow should stop once the well has stabilized thermally, if, however, there is overpressure, the flow will not stop even with the well thermally stabilized.

During an injectivity test in a well with two permeable zones, the upper zone may produce or accept fluid depending on the flow rate injected according to equation (6).

Thermal effects on injectivity tests and fall-offs in wells with two permeable zones can be utilized to extract information about the two zones separately. The procedure is quite simple and uses measurements of temperature and flow rate to obtain a theoretical response that is matched against measured pressure data by adjusting the value of injectivity indexes of the two permeable zones.

The technique proposed has the uncertainty associated with the assumptions made, especially the one regarding temperature of the liquid column between the permeable zones. Practical application of this method would benefit substantially if measurements of pressure and temperature were made in the two permeable zones simultaneously.

ACKNOWLEDGEMENTS

The support of the Costarican Institute of Electricity (ICE) in the preparation and publication of this work is gratefully acknowledged.

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