DETECTION OF NATURAL FRACTURES FROM A DRILLSTEM TEST

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ABSTRACT

The presence and magnitude of natural fractures in a potentially productive zone may have a significant effect on the completion of that zone. Their existence may dominate the pore space of the rocks and control the production rate. In addition, the method and materials required to stimulate this heterogeneous system may require special attention. This paper discusses the detection of fractures from the pressure buildup behavior of a drillstem test, and how this behavior may be distinguished from unconnected layered zones and flow capacity discontinuities. A quantitative analysis making this distinction is demonstrated by a Horner plot, square root of time plot, and Gringarten curve fit. The magnitude of the fractures may be estimated.

INTRODUCTION

Most well testing techniques such as drillstem testing are based on the assumption that the reservoir is isotropic and homogeneous in the region of influence. Even though this assumption is rarely satisfied and reservoir heterogeneities do exist, the results appear to be reasonable and usable as completion criteria. However, in some cases these heterogeneities are of such magnitude that the pressure behavior is significantly disturbed to such an extent that an analysis is very difficult and sometimes incorrectly applied. A naturally fractured reservoir is among the most common identifiably heterogeneous systems encountered in drillstem testing. It is conceivable, and demonstrated by an almost infinite number of strange and erratic pressure behaviors, that natural fractures may occur in almost any geometric arrangement. Perhaps, the most common fracture system is one that exhibits two distinct porosity types: a matrix that may contain pore spaces and a system of interconnecting fractures and fissures. Many times these two porosity types are significantly contrasting, with small pores and larger, more conductive fractures. It is this condition that may demonstrate itself more noticeably on a drillstem test than one with a lesser contrast which may appear as a homogeneous, isotropic rock. A number of authors have made model studies using various geometric rock structures and flow regimes with reasonably comparable results.[1,2,3] Basically, matrix flow at some distance from a fracture may be radial and in a semi-steady state condition. As the flow approaches a fracture, especially in a vertical linear and diametrically opposing configuration, it may approach and finally become linear at its juncture with the fracture. This flow pattern is described by some as elliptical in shape.[1,4] Wellbore storage may demonstrate itself in the very early pressures, but its duration may be short. Theoretically, all these conditions may appear as shown in Figure No. 1; however, elliptical flow is very difficult to recognize. The most common occurrence is linear and semi-steady state flow.

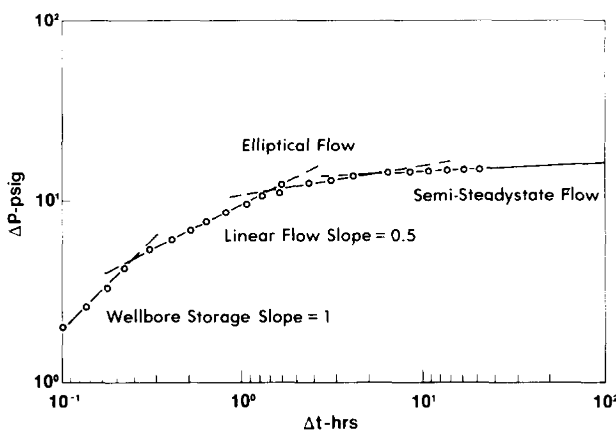

FIGURE 1—FLOW REGIMES

It may be significantly important to detect natural fractures when they exist in a potentially productive zone. The first problem that may exist is the inability to maintain a packer seat while open hole drillstem testing. An attempt to retest after a packer seat failure with a larger packer element may not be successful and may result in a stuck packer. The aid of a pressure-distributor valve between tandem packers may help maintain a seat.

The knowledge that natural fractures exist and an approximation of their magnitude may indicate the need for and the design of fluid-loss control in stimulation treatments. Unfortunately, natural fractures many times exist in low-permeability formations; those that require a very long induced fracture length for a favorable production increase. Fluid-loss control is most important in this case. Many low-permeability, low-porosity, naturally fractured formations may not be commercial without the aid of fractures. These fractures serve as the primary porosity. Knowledge of this condition is essential and may be detected on a drillstem test.

QUALITATIVE ANALYSIS

The first indication of fractures on a drillstem test is demonstrated in the pressure buildup behavior. Figure Nos. 2 and 3 are examples of this behavior. The buildup does not behave normally as in the first buildup of Figure No. 2 but appears to start its closure (making the turn) then develops a uniform (with some curvature) pressure increase, as demonstrated in the second buildup. Figure No. 3 shows both buildup curves with this character. As the contrast of porosity (or permeability) decreases, the character of the buildup pressure may be less noticeable due to no apparent change in behavior. In these cases, a quantitative analysis must be made to detect the fractures. Unfortunately, a permeability discontinuity will demonstrate the same character. A quantitative analysis will demonstrate the difference.

QUANTITATIVE ANALYSIS

The normal procedure for reading the pressure behavior on a drill stem test is 10 to 20 equal increments. This is usually sufficient for a Horner plot, but neglects the early pressure behavior which is essential for fracture detection. The buildup

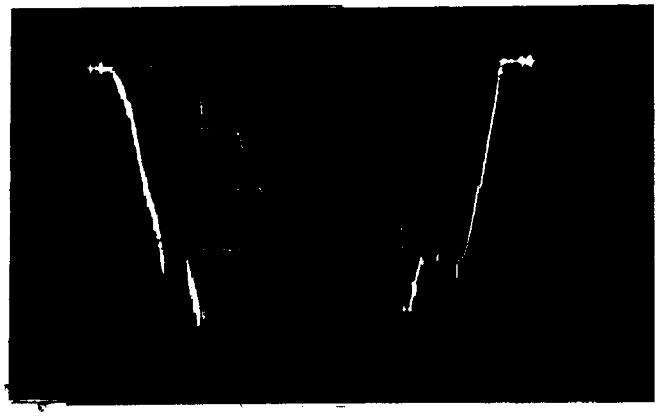

FIGURE 2—DRILLSTEM TEST PRESSURE RESPONSE, RADIAL FLOW ON INITIAL AND LINEAR FLOW ON FINAL BUILDUP

FIGURE 3—DRILLSTEM TEST PRESSURE RESPONSE INDICATING NATURAL FRACTURES

should be read in 1 minute increments for the first 10 minutes, 2 minute increments for the next 20 minutes, and 10 minute increments for the remainder of the time, or some equivalent pattern.

Horner Plot

Theory [1,3] predicts a Horner pressure buildup of a fractured formation will have two semilog straight line portions, one at early times and one at late times connected by a transition, as in Figure No. 4. The semilog straight lines should theoretically be parallel; therefore, either of them may be used to calculate formation characteristics. However, the later one is used to indicate reservoir pressure. Note that these slopes are not parallel. This could be caused by having an inconsistent production rate. The transition shape and length is influenced primarily by the contrast of the primary and secondary porosities and permeabilities. For instance, a large contrast in porosities will cause the transition to displace the later semilog straight line, resulting in a longer transition, while a large contrast in permeability will cause the transition to occur at very early times. Unfortunately, this double slope is very often not observed in drillstem test pressure behavior. This may have been because very little attention has been paid to early pressures until recently, or because the early portion of the curve may be obscured by wellbore storage effects. Perhaps, the most logical reason is that there may be a large contrast in permeabilities which would cause the transition period to appear immediately.

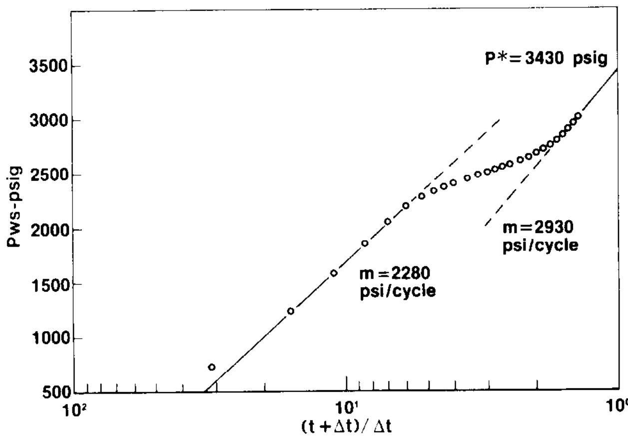

FIGURE 4 HORNER BUILDUP PLOT OF A NATURALLY FRACTURED RESERVOIR

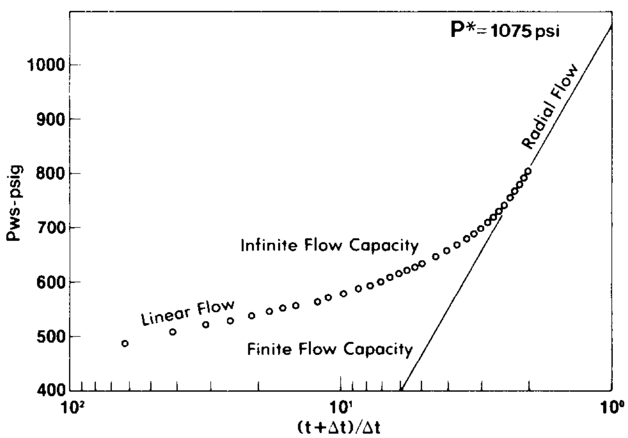

FIGURE 5—TYPICAL HORNER PLOT OF A FRACTURED RESERVOIR

The most common buildup shape of a Horner plot is shown in Figure No. 5 and demonstrates the transition and late semilog straight line. The first quantitative indication that fractures may exist is that transition or early pressure points will develop above the ideal semilog straight line. These early points will not form a straight line even though they may have that appearance. The earlier portion of the transition period is in linear flow, while the later portion may be elliptical. If this transition period is very flat or not displaced very far above the semilog straight line, the fracture flow capacity is more finite; whereas, if the transition is further displaced, the flow capacity is more infinite, as indicated in Figure No. 5.

Three other conditions may exist which could appear to demonstrate the same character. The first, and perhaps the most common, is a pressure buildup with insufficient closure. That is, one that has not "made the turn" as a triangle. Check the chart to be sure that this is not the case. Secondly, a permeability discontinuity may have the same appearance both qualitatively and quantitatively, except the early pressure points on a Horner plot will definitely form a straight line, resulting in a double slope buildup. This anomaly does exist in drillstem test pressure behavior, but not as often as natural fractures. Therefore, special attention must be exercised not to misinterpret this behavior. Thirdly, a layered formation without crossflow may demonstrate an early semilog straight line, a transition or flattening, and then another semilog straight line. Each of the straight lines will have a different slope since they each responded to a different layer of flow capacity and reservoir pressure. This is contrary to the theoretical parallel slopes of naturally fractured formations and should not be interpreted as such. To confirm that a layered formation does exist, the pressure buildup should appear as a double buildup with the appearance of one buildup superimposed on another.

P_{ws} vs $\sqrt{t}$ Plot

A cartesian coordinate plot of wellbore pressure vs. the square root of time may indicate linear flow by having the early pressures fall on a straight line as shown in Figure No. 6. These points will coincide with the early portion of the transition period of a Horner plot. A finite capacity fracture may display a curved portion before getting on a straight line of proper slope. The lower the fracture capacity is, the longer the duration of the curved portion. For very low-capacity fractures, it may be almost impossible to determine if a straight line does indeed develop. In this instance, the flow may appear radial. After the initial linear flow period, there may be a transition to an infinite-acting, pseudoradial flow period in which the normal semilog analysis applies. The slope of the straight line is inversely proportional to the fracture length.[5] This plot may quickly indicate the presence and magnitude of natural fractures.

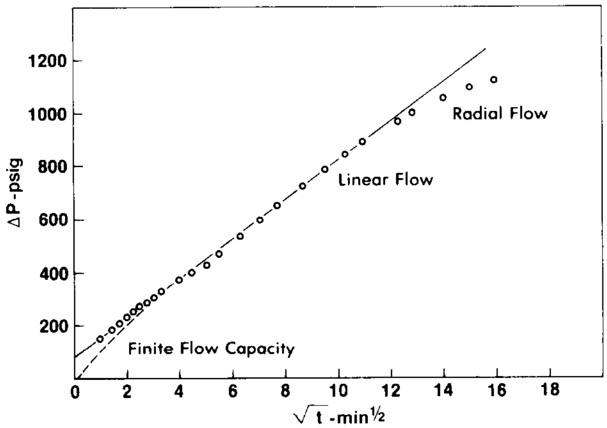

FIGURE 6—FLOW REGIMES OF WELLBORE PRESSURE VS. SQUARE ROOT OF TIME

Type-Curve Match

When a buildup test does not have good closure and is not applicable for the semilog straight line analysis, type-curve matching may be employed to help determine formation characteristics. Gringarten et al.[6] type curves for infinite-conductivity vertical fractures located in the center of a closed square drainage region and producing a slightly compressible constant-viscosity fluid at a constant rate may be used to quickly detect a fracture. Figure No. 7 demonstrates a log-log plot of dimensionless pressure drop, P_D, vs. dimensionless time, t_D for these conditions. The early pressure points following $X_e/X_f = \infty$ line will develop a half-slope straight line. This is linear (fracture) flow and corresponds to the straight line on the wellbore pressure vs. $\sqrt{t}$ plot and the early portion of the transition of a Horner plot. Beyond the half-slope line represents the transition from linear to radial flow response at the well.

To evaluate a pressure buildup response, a plot of ΔP vs. Δt is made on 3 x 5 log-log transparent grid, such as Figure No. 8. This plot is placed on the type curve (Figure No.7) and moved along the $X_e/X_f = \infty$

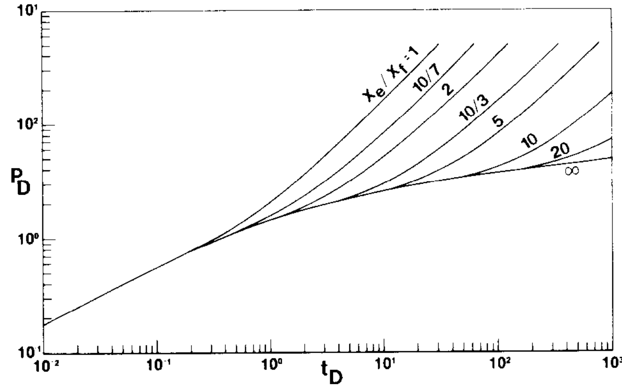

FIGURE 7 TYPE CURVE FOR A VERTICAL FRACTURE, AFTER GRINGARTEN ET AL.

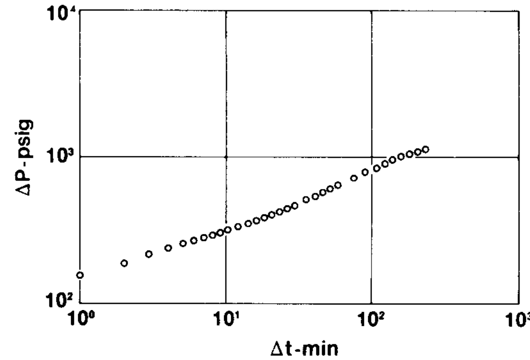

FIGURE 8—LOG-LOG PRESSURE BUILDUP PLOT FOR A TYPE-CURVE MATCH

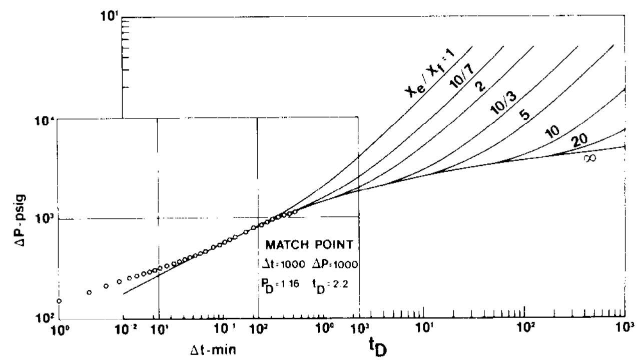

FIGURE 9 TYPE-CURVE MATCH

line until a match is made, such as Figure No. 9. A match on a fracture type curve indicates natural fractures in the reservoir. Note that the early pressures are less (flatter) than one-half slope and do not follow the $X_e/X_f = \infty$. This may be caused by conditions such as finite flow capacity of the fracture, disturbance caused by damage, inaccurate pressure readings, or phase redistribution. If the plot tends to turn upward following one of the X_e/X_f curves, a boundary is indicated. Theoretically, if a closed system exists, the plot may follow the $X_e/X_f = \infty$ beyond the semilog straight line portion then flatten below the $X_e/X_f = \infty$ curve. However, this author has not observed this characteristic.

A fracture at the wellbore will give a pressure response as a flow capacity improvement or a negative skin effect. There are several forms of the skin formula. The basic van Everdingen-Hurst radial flow for Horner or MDH plots follows:

$$s = 1.15\left[\frac{P_{1\ hr} - P_{wf}}{m} + \log\left(\frac{t+1}{1}\right) - \log\left(\frac{K}{\phi\mu C_t r_w^2}\right) + 3.23\right]$$

Where:

s = skin factor, dimensionless
$P_{1\ hr}$ = pressure at 1 hr on the Horner plot, psi.
P_{wf} = bottomhole flowing pressure, psi
m = slope of buildup on Horner plot, psi/cycle
t = flow time, hr
K = permeability, md
ϕ = porosity
μ = viscosity, cp
C_t = total compressibility, psi^{-1}
r_w = wellbore radius, ft

Flow efficiency may be determined from the pressure drop across skin effect. The inverse of flow efficiency is damage ratio and is normally used in drillstem testing. Damage ratio formulas are very approximate in that formation characteristics such as permeability, porosity, viscosity, compressibility, and wellbore radius are estimated and expressed as a constant. Theoretically, a damage ratio of one implies no damage; therefore, it follows that a ratio of less than one may imply flow capacity improvement or a negative damage. Since these formulas are approximate, care should be exercised in their use for this analysis.

The Gringarten et al. natural fractures type curve for curve matching is:

$$s = -\ln\left(\frac{X_f}{2.718 r_w}\right)$$

Where:

s = skin factor, dimensionless
X_f = half fracture length, ft
r_w = wellbore radius, ft

After X_f has been determined from a type-curve match, the skin may be determined as above. This will, of course, result in a negative skin, basically because of a flow capacity improvement at the wellbore.

Skin effect varies from approximately -5 for the most severe (high conductivity) fractures to infinity for positive effects.

CONCLUSIONS

1. Infinite flow capacity natural fractures may be qualitatively detected from the pressure buildup behavior of a drillstem test. Finite flow capacities may be detected, but with more difficulty.
2. Drillstem test pressure behavior for fractured reservoirs does not often demonstrate itself as a theoretical, parallel double semilog straight line plot, but as a transition followed by a semilog straight line.
3. The Horner plot, wellbore pressure vs. the square root of time, and type-curve matching are all effective methods for detecting natural fractures.

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