RECEIVED BY TIC AUG 28 1979

To be presented at the Annual Meeting of the
Society of Petroleum Engineers, Las Vegas,
NV, September 23-27, 1979

LBL-9303

CONF-790920--1

DOWNHOLE PRESSURE CHANGES MEASURED WITH A FLUID FILLED CAPILLARY TUBE

C. W. Miller and J. M. Zerzan

July 1979

Prepared for the U. S. Department of Energy
under Contract W-7405-ENG-48

MASTER

LAWRENCE BERKELEY LABORATORY
UNIVERSITY OF CALIFORNIA
BERKELEY

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

LEGAL NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Department of Energy, nor any of their employees, nor any of their contractors, subcontractors, or their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately owned rights.

DOWNHOLE PRESSURE CHANGES MEASURED WITH A FLUID FILLED CAPILLARY TUBE

C. W. Miller and J. M. Zerzan

Earth Sciences Division
Lawrence Berkeley Laboratory
University of California
Berkeley, CA 94720

NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Department of Energy, nor any of their employees, nor any of their contractors, subcontractors, or their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately owned rights.

To be presented at the Annual Meeting of the Society of Petroleum Engineers, Las Vegas, Nevada, September 23-27, 1979.

ABSTRACT

An analysis was done on the transmission of a pressure signal through a small diameter (≈ 0.14 cm) fluid transmission line. The effects of the viscosity and compressibility of the fluid, of the tubing size, and of the temperature changes with time were investigated. Both an oil and a nitrogen filled tube were considered. For a small disturbance, say 1% of the bulk modulus, the propagation of the pressure signal was characterized by a diffusion equation with a source term. For large disturbances, compressibility effects become significant and the signal propagation must be described by a wave equation with damping. A comparison was done between the theoretical model and experimental results with excellent agreement. An oil filled tubing could be described by the small disturbance equation. The pressure response of a nitrogen filled tubing was modelled with the large disturbance equation. It is also shown that for the former case, the wellhead data can be inverted to give the actual downhole pressure using a minimization technique.

INTRODUCTION

Well testing in a geothermal field requires instrumentation that can withstand high temperatures and high salinity. The existing instrumentation which could be used (such as the Kuster pressure tool), has an accuracy and resolution less than desired, does not have the capability to record pressures for extended periods of time at high temperatures (usually around 12 hours), and does not allow pressure monitoring at the surface during the test. One method of measuring the downhole pressure that has eliminated some of the above problems is to use a fluid filled transmission line as suggested by Fournier[1]. The method utilizes a fluid filled capillary tube that is attached to a pressure transducer at wellhead and to a larger diameter chamber downhole (see Fig. 1). The downhole chamber minimizes changes in the brine/fluid interface position during a drawdown or buildup test. The pressure transducer is not subject to the harsh environment of the well, and the downhole pressure can be monitored continuously during a test. The system requires a fluid (either gas or liquid) that will not undergo a phase transition at the pressures and temperatures of interest, and tubing small enough in diameter so it can be easily lowered downhole. However, any fluid transmission line will distort and delay the downhole pressure signal. The amount of distortion depends on the compressibility and the viscosity of the fluid and the signal shape itself. High frequency signals are attenuated more and have a greater phase lag than lower frequencies. A signal wave form generated at one end of a fluid filled capillary tube will arrive as a different wave form at the other end Also, any temperature changes in time along the tube, create additional pressure pulses which further distort the downhole signal. To interpret the data correctly these effects must be understood. In some cases, it is possible to invert the measured signal and obtain the actual downhole pressure changes as a function of time.

The attenuation of a transmitted signal by a fluid transmission line has been considered previously. Iberall[2] looked at the distortion of oscillating pressure signals in instrument lines while other authors[3-6] dealt with the response of a general pressure transient signal. Unfortunately, they have dealt only with small disturbances and have not included outside temperature changes. A small disturbance is approximated as a pressure change less than 1% of the bulk modulus, $\Delta P < 1\% \ \rho(\partial P/\partial \rho)_T$, assuring that changes in ρ are small. When a liquid is used as the fluid, pressure changes as large as 15MPa will qualify as a small disturbance because the bulk modulus is so large. On the other hand, when gas is used, the pressure change must usually be less than 1% of the pressure to be considered a small disturbance. When the pressure in the tubing is about 15MPa, a pressure change greater than 0.15MPa must be analyzed as a large disturbance. Because the gas requires a more detailed solution, one might think it would be easier to just use a liquid such as oil in the tube. However, any temperature changes in time along the tubing produce pressure pulses. More distortion arises with the liquid filled line than the gas filled tubing because the liquid is less compressible. Both of the fluid types have drawbacks and for a complete analysis of the system, both of these problems must be considered.

References and illustrations at end of paper.

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

To make better use of the measured data, it is of interest to also solve the inverse problem, i.e., given the measured pressure signal, how does one obtain the actual downhole signal. This paper reviews the equations that describe the propagation of a small and of a large disturbance including transient temperature effects. The equations have been solved numerically, and the solutions have been compared with experimental values. The effect of the fluid type, the tubing diameter, and the tubing length have also been considered. A least squares minimizing technique reported in the heat transfer literature has been used to invert the data for the small disturbance case. In general, excellent agreement is obtained between the numerical and experimental results. Except for cases with highly distorted and delayed signals where damped oscillations occur, good results were obtained for the inverse problem. A unique solution for inverting data in the large disturbance case has not been determined to date.

DEFINING EQUATIONS

One dimensional transient flow is assumed. The equations used to describe the flow are:

continuity, $$\frac{\partial \rho}{\partial t} + \frac{\partial}{\partial x}(\rho u) = 0 \qquad (1)$$

and momentum,

$$\frac{\partial}{\partial t}(\rho u) + \frac{\partial}{\partial x}(\rho u^2) + \frac{\partial P}{\partial x} + \rho g + \frac{1}{2}\frac{f\rho u^2}{D} = 0. \qquad (2)$$

The capillary tube is so small in relation to the well itself, it is assumed that the temperature of the tubing instrument will be at the same temperature as the brine surrounding it. In most cases every time there is a flow rate change in the wellbore, the temperature at any point in the well will increase or decrease imposing a temperature change along the instrument. It is assumed that there is some knowledge of this temperature change with time, either through measurement or by the modelling of the well flow. An equation of state, relating the density to pressure and temperature, completes the set of equations.

In the momentum equation, the viscous term has been expressed as a friction factor times $1/2\ \rho u^2/D$. For laminar flow, $f = 64/Re$, where Re is the Reynolds number and is equal to $\rho uD/\mu$. For turbulent flow in a smooth tube, the friction factor has been expressed as $0.18\ Re^{-0.2}$ which is valid over the range of $1760 < Re < 10^7$. Below $Re = 1760$, the flow is laminar.

The tubing length is L with the downhole chamber being at $x = 0$ while the pressure gauge is at $x = L$. Initially, the fluid is quiescent, $u(x,t = 0) = 0$, and only a static profile exists in the tube,

$P_o(x) = -\int_o^x \rho_o g dx + P_r$. The boundary conditions are:

$u(L,t > 0) = 0$

$P(0,t > 0)$ or $P(L,t > 0)$ is known,

and $T(x,t \geq 0)$ is known.

It is also assumed that the brine/fluid interface in the larger chamber downhole does not change significantly because of the large difference in diameter between the capillary tube and the chamber. When fluid exits or enters the capillary tube, there will be only a small change in the interface insuring that the pressure is being calculated at the same point.

The equations can be simplified and solved. First the solution for the small disturbance will be considered and then the method for a large disturbance will be presented.

SMALL DISTURBANCE

For a small disturbance, the fluid velocity as well as changes in the fluid density are small. Equation 1 reduces to

$$-\frac{1}{\rho}\frac{\partial \rho}{\partial t} = \frac{\partial u}{\partial x} \qquad (3)$$

Because the fluid velocity is small, laminar flow is assumed so that $1/2 f\rho u^2/D$ reduces to $(8\mu/R^2)u$. To solve both Equations 2 and 3, the derivative of Eq. 2 is taken with respect to x and $\partial u/\partial x$ is replaced using Eq. 3. The equation of state, $d\rho = \rho\beta\ dT + \rho C_t dP$ is used to relate the density changes to those of pressure and temperature. If second order terms as $\partial^2\rho/\partial t^2$ are ignored, the resultant equation obtained is

$$\frac{\partial^2 \rho}{\partial t^2} = \frac{R^2}{8\mu C_t}\frac{\partial^2 P}{\partial x^2} - \frac{\beta}{C_t}\frac{\partial T}{\partial t} + \frac{R^2 g}{8\mu C_t}\frac{\partial \rho}{\partial x} \qquad (4)$$

The first term on the r.h.s. is just the diffusion of a pressure pulse down the tube. The second term is the pressure pulse generated by a temperature change in time, and the last term is due to changes in the balance of gravity which is usually small. For $R^2/8\mu c_t \simeq$ constant, one has a linear diffusion equation with a source term. This equation will be used to analyze a liquid filled transmission line.

LARGE DISTURBANCE

For a gas filled transmission line, u and $\Delta\rho$ are no longer necessarily small and cannot be neglected. The solution procedure is to combine the continuity equation and the momentum equation as in the small disturbance case. The term $\partial^2\rho/\partial t^2$ cannot be neglected, resulting in a wave like equation with damping:

$$\frac{\partial^2 \rho}{\partial t^2} = \frac{\partial^2}{x^2}(\rho u^2) + \frac{\partial^2 P}{\partial x^2} + g\frac{\partial \rho}{\partial x} + \frac{\partial}{\partial x}\left[\frac{f\rho u^2}{2D}\right] \qquad (5)$$

The density changes are again written as a function of pressure and temperature using the equation of state. Laminar flow cannot be assumed. The appropriate expression must be used for f depending on whether the flow is turbulent or laminar. More details of the derivation of these equations is given in Reference 7.

The equations were solved numerically. The solution procedure is given in Reference 8. Experimental tests were set up to determine if the equations (4 and 5) could be used to model the fluid transmission line. In one case, 10cs oil was used as the fluid and in the second case, nitrogen was used. The experiment was to measure the arriving pressure signal for a step change in pressure at the other end. The capil-

lary tubing was 2400 m in length and had an inner diameter of 0.0014 m. The pressure was recorded at both ends, one with a Hewlett Packard gage and the second with a Sperry Sun gage. Eq. 4 was used to model the oil filled tube, and Eq. 5 was used to model the nitrogen filled tube. Figure 2 shows the comparison between the experiment and the theoretical model. One can see that there is excellent agreement. In the one case with an oil filled tube, the initial pressure was 7.5MPa and a step change of 3.4MPa was imposed. In the second case, the initial pressure of the nitrogen was 4.0MPa and a pressure change of 3.2MPa was imposed. If the small disturbance equation had been used to model the nitrogen case, the calculated response would have been too quick. More details of the experiment and the calculations are given in Reference 7.

SIGNAL RESPONSE

Given that either equation 4 or 5 could be used to model a fluid transmission line, one can use these equations to determine the response of the instrument in different circumstances. First, in a self-flowing liquid filled well, the wellhead pressure measurement itself would probably give a better estimate of the downhole signal than the fluid transmission line. The well itself is acting as a transmission line and the frictional losses in the well would be far less than in the capillary tube. The liquid filled well can be modelled just as easily as the fluid filled capillary tube. However, in many geothermal wells, the brine at the wellhead is usually flashed. Wellhead pressure measurements in this case are difficult to analyze, requiring modelling of the two phase flow conditions in the well. Such a model depends on a knowledge of friction factors and slip phenomena. These effects are not well known. For this situation, the fluid filled capillary tube can be modelled more accurately than the well flow itself. However, to invert the measured pressure signal and to obtain the actual downhole pressure, it is best to use a fluid transmission line that distorts the signal the least amount. To understand the effect of fluid, temperature, pressure and tube size on the measured signal, it is necessary to look at the effect of the system on a typical signal.

To simulate a typical drawdown curve, the equation

$$P_{downhole} = 1.35 \times 10^7 - 1.2 \times 10^6 \left(1 - e^{-t/5}\right) - 10^5 \ln\left(\frac{t + 10}{10}\right) \qquad (6)$$

was used. The first term in the equation is the initial pressure, the second term simulates a drop in pressure due to wellbore storage, and the third term aproximates the straight line semilog plot that results at later times and is indicative of the reservoir itself. A very small wellbore storage constant was approximated because rapid changes in pressure are distorted significantly by the pressure sensing system.

Figure 3 illustrates both the above equation which simulates the pressure at the well bottom and the response that would be measured at the surface using the capillary tubing with different fluids. For these calculations, it was assumed that the temperature of the instrument did not change in time and that the diameter of the tubing was 0.0014 m. (The former assumption is not really appropriate in a geothermal well but is of interest to first investigate the isothermal response and then consider the effect of temperature and of tubing size.). Curve (b) gives the response for 10 cs silicone oil at 180°C. There is a small delay before any signal is measured at wellhead. The measured curve coincides with the simulated drawdown curve after approximately 7 minutes. Curve (c) plots the response using nitrogen in the tube and curve (d) shows the response for the 10 cs oil at 21°C. This last case is very slow, taking at least 30 minutes before the wellhead and downhole pressure would coincide. The large change in response between curve (b) and curve (d) is because of the large increase in viscosity of the oil when the temperature decreases. For the oil filled tubing, the response is controlled by the diffusivity, $R^2/8\mu c_t$. As the viscosity increases, the damping effect is increased because the diffusion coefficient gets smaller. From the figure, it is evident that the oil filled tubing should not be used at low temperatures unless the tubing radius is increased substantially. However, as the tubing radius increases, the tubing cannot be handled very easily and an elaborate system is needed at wellhead for installing the tubing. For the oil filled tube and for the constant temperature in time case, an estimate of the time required for the measured signal at wellhead to reflect a given downhole pressure drop is when $t > 5L^2/4k$ where $k = R^2/8\mu c_t$.

When nitrogen is used as the pressure sensing medium, the propagation of a pressure signal is also very dependent on the compressibility of the fluid. Although the viscosity becomes very small, the compressibility increases. Also, the wave nature of the flow is important and is dependent on the compressibility. The compressibility, though, is inversely proportional to the pressure. As the pressure decreases, the response of the instrument also decreases. For a given length of tubing, it is best to measure the pressure drop in the well, where the pressure is highest, because the time for the disturbance to through the fixed length of tubing will be less. In Figure 3, the pressure level in the tubing was relatively high, so that the response was almost as fast as the case using oil at high temperatures.

With this measuring instrument, the very early time data of either the pressure drawdown or buildup curve is due to the measuring instrumentation and not the well itself. Figure 4 plots the signals obtained in the isothermal case with a high temperature oil filled tube. Curves 1 and 2 show the simulated drawdown curves, one with an early time drop of $-180\,(1 - e^{-t/5})$ and the second with a change of $-180\,(1 - e^{-t/50})$. The pressure signals that would be measured at the other end are given by 1′ and 2′ respectively. One might try to take the response curve 1′ and analyze it as a wellbore storage curve. Actually, the slope of the curve is not one to one on the log-log scale as one might expect. However, it can be shown[9] that in a geothermal well, one should not expect a one-to-one plot of early time data anyway, because the reservoir can respond quickly and the time for a disturbance to propagate down the well is important. But although there is almost an order of magnitude difference in the rate of the initial pressure drop between curves 1 and 2, the difference between curves 1′and 2′ is much smaller. The next section shows how the wellhead measurement can be inverted to obtain the downhole signal even in this situation.

From the initial comparison it seemed as if the high temperature oil gave the best response. However, the response was calculated with no change of temperature with time along the tubing. As stated, this assumption is not realistic in a geothermal field. Because the oil is almost incompressible, any increases in temperature at a point are manifested as large increases in pressure. The pressure signal generated is $(\beta/c_t)\partial T/\partial t$. This situation means that even though the downhole pressure is dropping at one end, the measured surface signal may actually increase in early times. This case has been observed in field data.[10] To alleviate this problem, the well is flowed until the change in temperature with time is less than say, 1°C over 1 hour. Then, the flow rate is changed. Even in these circumstances, small temperature changes still take place in the well because of changes in the heat loss out of the well and because of changes in the flash point level. To investigate this temperature effect, a change in temperature in the well was approximated as

$$T(x,t) = \frac{-3x}{2400} e^{-t/150} \frac{-13x}{2400} + 181$$

At time t = 0, the temperature profile along the wellbore is (181 - 0.0054x)°C. The temperature at wellhead is 165°C. After the flow rate change, the temperature at wellhead is 168°C. The average temperature change over the length of the well is only 1.5°C. This small change will produce a large change in the measured surface pressures using a capillary tube system. Figure 5 is a plot of the pressure response when the wellbore temperature changes in time. Curve (a) is again the simulated drawdown, curve (b) is the response for the 10 cs oil at 180°C, and curve (c) is the response for the oil when the temperature changes according to the above equation. The pressure response increases and then slowly decreases. For this relatively small ΔT change in time, the measured signal now takes almost 10-15 minutes to approach the simulated drawdown curve instead of just 5-7 minutes. Moreover, there is initially a pressure increase when the actual downhole pressure is decreasing. When nitrogen is used with this small temperature change, the response is almost identical to curve (c) assuming an average pressure of 15MPa in the tube. For the isothermal case, the oil responds faster than the nitrogen. However, when there is a small temperature change with time, a much larger pulse is imposed on the oil filled tube than with the nitrogen filled tube for the same $\partial T/\partial t$. The time for the signal to approximate the downhole pressure will be about the same for the oil or nitrogen filled transmission line in this case. For a larger $\partial T/\partial t$, the oil response will become more distorted than the nitrogen.

Because the small tubing diameter has such a large effect on the signal, the pressure response was analyzed for different sizes. Figure 6 plots the pressure response for the nitrogen filled tube with an average temperature change of 1.5°C and for three different reasonably sized capillary tubes: 0.27 cm, 0.14 cm, and 0.066 cm in inner diameter. One sees that the smallest sized tubing produced a very large distortion even in the nitrogen case. The larger sized tubing produced much better results; i.e., the response time was only about 4 minutes instead of about 10 minutes even with the average temperature change of 1.5°C.

Looking at the tubing response it would seem that when choosing a fluid pressure transmission system the following recomendations can be made to minimize the amount of signal distortion:

(1) capillary tubing of 0.066 cm is too small to be used at all;

(2) if the temperature is high (say 180°C) and the change of temperature with time is negligible, 10 cs silicone oil gives less distoration than nitrogen;

(3) if the temperature is low or changes in time, and if the average pressure in the tube is high, (say 15MPa) nitrogen is the best fluid; and

(4) at low temperatures and low pressures, the system shouldn't be used.

INVERSION OF WELLHEAD DATA

Before choosing the most appropriate fluid transmission system, it is important to determine if the wellhead data can be corrected, i.e., given the measured pressure response, can one invert this profile to obtain the pressure signal that caused it. This case is usually referred to as the "inversion problem." A unique solution is not necessarily always possible. At present, it has been possible to get reasonable solutions to this inversion problem for the "small" disturbance equation. The oil filled tubing data can be inverted in most cases. However, the inversion for the nitrogen filled tube and resultant "large" disturbances has not yet been determined. The reason for this difficulty will be evident below.

The small disturbance equation is really just a diffusion equation with a source term. This same type of equation is important in heat conduction problems. The solution to the inverse heat conduction problem has been considered previously. Exact solutions are available for the linear case.[11] However, the exact solution requires a continuous pressure measurement in time. The inverse solution is a convergent series dependent on derivatives of pressure with time. The more distorted the signal is, the more higher order derivatives are needed. Accurate measurement of these derivatives may not be available from point measurements. Another method of inverting the data is the nonlinear estimation technique used by Beck[12]. The method is to minimize the difference between the calculated response of the system for a given value of P or $\partial P/\partial x$ at the bottom of the well and the measured response over some time interval. The minimization is done with respect to the boundary condition that is guessed, i.e., P or $\partial P/\partial x$. Because there is a delay in time before changes downhole can be measured at wellhead, the minimization is done over a number of "future times." The number of future times depends on just how long the delay is. If a signal takes 10 sec to produce a measurable value at wellhead, then the minimization to obtain the boundary condition downhole at time $t^{\ell+1}$ must be over the interval t^{ℓ} to $t^{\ell+1}$ + 10 sec. If the signal takes longer to arrive at wellhead, the minimization must be over more future times. A detailed description of the method is available in either Reference 12 or 13, but because the method is of particular interest, a very brief description follows.

Define q as $\partial P/\partial x$. Now given P at wellhead, one must determine q downhole. Say q^{ℓ} (ℓ denotes the time level) is known. Then how is $q^{\ell+1}$ determined? The idea is to guess $q^{\ell+1}$ and denote the guess as $q_m^{\ell+1}$ with

m indicating the iteration level. Usually it is assumed that as a first guess $q^{\ell+1} = q^{\ell}$. The next guess for $q^{\ell+1}$ is just $q^{\ell+1} + \Delta q_m$, where

$$\Delta q_m = \frac{\sum_{i=1}^{r} \left[Y^{\ell+1} - P_m^{\ell+1} \right] \phi_m^i}{\sum_{i=1}^{r} \left(\phi_m^i \right)^2}$$

The ϕ_m^i are the sensitivity coefficients, i.e., if q is changed, how much do the calculated values change. The sum is done from i = 1 to r where r gives the number of future times. The small disturbance equation can be solved numerically given the value of q.

The method was used to invert the simulated drawdown data. It was also used for some experimental measurements. The comparison of the inverted solutions and the exact solutions are given in Figures 7-9.

In Figure (7a), the inversion method was performed for a diffusion coefficient of 40,000 m^2/sec, corresponding to 10 cs oil at 180°C in a tube of radius 0.14 cm. First, the measured data was obtained by using the simulated drawdown curve Equation 6 with $e^{-t/5}$ replaced by $e^{-t/50}$. Then, the "measured" data was inverted using the minimization technique to obtain the expected drawdown curve. Because the signal took about 8 sec to arrive at wellhead, the minimization was over 8 sec of future time. One can see that there is excellent agreement. However, as the inversion method is used on more and more distorted curves, oscillations appear. This problem is evident in Figure (7b). Again, the diffusion coefficient was 40,000 m^2/sec, but the simulated drawdown curve was Eq. 6 with the term $e^{-t/5}$, which creates a steeper initial drop in the pressure. The simulated curve was used to calculate the "measured" values. These values were then inverted to obtain the original disturbance. However, oscillations start to appear because the measured values have a limited accuracy. The more accurate the values are, the smaller the oscillations will appear. Nevertheless, the oscillations are symmetric about the actual solution and realizing this result, the actual solution could probably be obtained within reasonable accuracy. First one inverts the measured data and gets the best results as possible. Then, knowing that the actual solution is not oscillatory, one obtains the actual solution by assuming the oscillations are symmetric about it. Using this assumed solution, one can recalculate the expected values and compare the calculated results with the measured values.

Figure 8 illustrates an even more damped and distorted case. In this figure, the diffusion coefficient used was 6000 m^2/sec (20°C oil), and the simulated curve to generate the data was Equation 6 but with $e^{-t/50}$ instead of $e^{-t/5}$. The minimization now had to be over 40 sec because the delay was so much longer. The oscillations are larger but they are symmetric about the actual drawdown signal and do damp out. Again when inverting, one can estimate the solution as just the average of the oscillations. Then this "guess" can be checked.

The only experimental data that was available where the actual pressure signal that caused the measured values was known, was for the case where a step function was imposed at one end of the tube and then the pressure signal was measured at the other end. The measurements were obtained at 20°C with 10 cs oil in a tubing 2400 meters in length. This situation is probably one of the "worst cases". Figure 9 shows what is calculated when trying to invert the data. Experimental values were taken only every minute. When inverting the data, very large oscillations are obtained, but one can see they are almost symmetric about the actual disturbance signal. The actual signal was a step jump from 10.9MPa to 14MPa. The calculated signal is just damped oscillations about the 14MPa line. Even in this "worst case," reasonable results are possible.

The inversion of the nitrogen data is not quite as straight forward. The method used for the inversion of oil filled tubing has been to guess a solution and minimize the difference between the calculated and measured value. However, the large disturbance equation is highly non-linear. Beck[12] stated his method could be used for the non-linear diffusion equation, but all his examples were for linear problems. When the coefficients are a function of time and position, it is not obvious that this minimization technique is applicable. For two differerent guesses of the pressure change downhole, one may calculate the same pressure change at wellhead. A unique solution may not exist.

For a gas filled tubing, the propagation of the pressure signal is inversely proportional to the pressure. As the pressure in the tubing decreases, the signal propagation decreases. Say one guesses a pressure drop that is larger than the actual change. Although the change in pressure is too large, the propation of this signal is slower than for the actual signal because the pressure in the tubing is lower. The calculated pressure change at wellhead for this guess may be the same as caused by the actual downhole pressure change. If one guesses a pressure drop too small, the signal is transmitted faster than in the actual case, and again the calculated response is the same. The attempts at inverting the nitrogen data have resulted in divergent solutions.

CONCLUSIONS

A fluid transmission line can be used to measure downhole pressure changes in a well with time, but the system does distort the signal. As the viscosity and the compressibility of the fluid increases, the distortion and delay of the transmitted signal increases with high frequencies being damped more than low frequencies. For the case when the pressure signal can be classified as a small disturbance, such as when oil is used as the transmitting fluid, the measured signal will not show the extent of a sharp pressure change until $t > t^*$ where $t^* = 5L^2/4k$ and $k = R^2/8\mu C_t$. When the time changes of interest are on the same order of magnitude or smaller than this t^*, such as in a two rate test, the amount of signal distortion must be considered. The time for the signal to propagate through the capillary tube will increase for any transient temperature effects along the tubing, say even an average change of 1/2°C over a couple of minutes. Also the time delay will increase if the pressure change of the fluid becomes too large with respect to its bulk modulus.

The oil filled tube system looks attractive because the measured data can be corrected easily to

obtain the actual downhole signal. However, if the temperature changes with time are not known, the inversion cannot be done. For large temperature changes with time where the rate of change is unknown, the nitrogen system may be better because it is less affected by temperature. On the other hand, the systematic inversion of data obtained with the nitrogen filled tube has not been determined. It is possible to just guess the drawdown curve and calculate the expected response. However, this method would be very tedious as there is no systematic way of guessing. Also, in the nitrogen case, the response is very dependent on the absolute pressure in the tube.

The device is a relatively simple way of continuously measuring downhole pressures. Nevertheless, there are problems and one should be aware of them before using or analyzing any data obtained with such a system.

NOMENCLATURE

C_t	isothermal compressibility of fluid $\rho^{-1}(\partial\rho/\partial P)_T$
D	inner diameter of capillary tubing
f	friction factor
g	gravity
k	$R^2/8\mu c_t$
L	length of tubing
P	pressure
P_i	initial pressure
P	pressure change
R	inner radius of capillary tubing
Re	Reynolds number = $\rho uD/\mu$
t	time
T	Temperature
u	velocity of fluid
x	distance
β	volumetric expansivity, $\rho^{-1}(\partial\rho/\partial T)p$
p	density
μ	absolute viscosity

ACKNOWLEDGEMENTS

This work was supported by the Division of Geothermal Energy, Department of Energy under contract No. W-7405-ENG-48.

References

1. Fournier, R.O. and Trusdell, A.M., "A Device for Measuring Dowhole Pressures and Sampling Fluids from Geothermal Wells," Geological Survey Research, U.S. Geol. Survey Prof. Paper 750-C, pp. C146-C150 (1971).

2. Iberall, A.S., "Attenuation of Oscillatory Pressures in Instrument Lines," J. Res. Nat. Bureau of Standards, v. 45, R.P. 2115, (1950).

3. Brown, F.T., "The Transient Response of Fluid Lines," J. Basic Eng. Trans. ASME, Series D., v. 84 p. 547 (1962).

4. Kantola, R., "Transient Response of Fluid Lines Including Frequency Modulated Inputs," J. Basic Eng., Trans. ASME, Series D, v. 93, p. 274 (1971).

5. Karem, J.I., Jr. and Leonard, R.G., "A Simple Yet Theoretically Based Time Domain Model for Fluid Transmission Line Systems," J. Basic Eng. Trans. ASME, v. 95, p. 498 (1973).

6. Schuder, C.B. and Binder, R.C., "The Response of Pneumatic Transmission Lines to Step Inputs," J. Basic Eng. Trans ASME, Series D, v. 81, p. 578 (1959).

7. Miller, C.W. and Haney, J. "Response of Pressure Changes in a Fluid Filled Capillary Tube," 2nd Invitational Well Testing Symposium, LBL Report Lawrence Berkeley Laboratory, Berkeley, CA. (1979).

8. Miller, C.W., "A Numerical Model of Transient Two Phase Flow in a Wellbore," LBL Report 9056, Lawrence Berkeley Laboratory, Berkeley, CA. (1979).

8. Miller, C.W., "Wellbore Storage Effects in Geothermal Wells," SPE Paper #8203, Presented at 1979 SPE Annual Technical Conference and Exhibitor, Las Vegas, Ne.

10. Narasimhan, T.N., "Applications of Well Testing to Liquid Dominated Geothermal Systems," 1st Invitational Wel Testing Symposium, LBL Report 7027, Lawrence Berkeley Laboratory, Berkeley, Ca, (1977).

11. Burggraf, O.R., "An Exact Solution of the Inverse Problem in Heat Conduction Theory and Applications," J. Heat Trans. U.86C, p. 373 (1964).

12 Beck, J.V., "Nonlinear Estimation Applied to the Nonlinear Inverse Heat Conduction Problem," Int. J. Heat and Mass Trans., v.13, 703-716 (1970).

13 Brass, B.R., "Application of the Finite Element Method to the Nonlinear Inverse Heat Conduction Problem Using Beck's Second Method," ASME Paper #78-WA/TM-1, Presented at Winter Annual Meeting of ASME, San Francisco, CA. (1978).

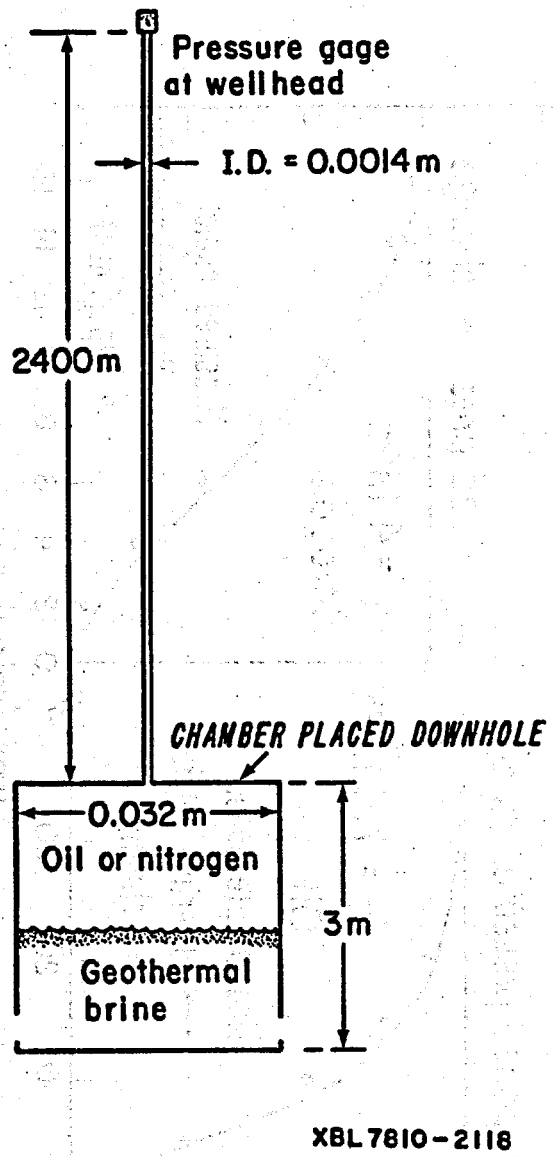
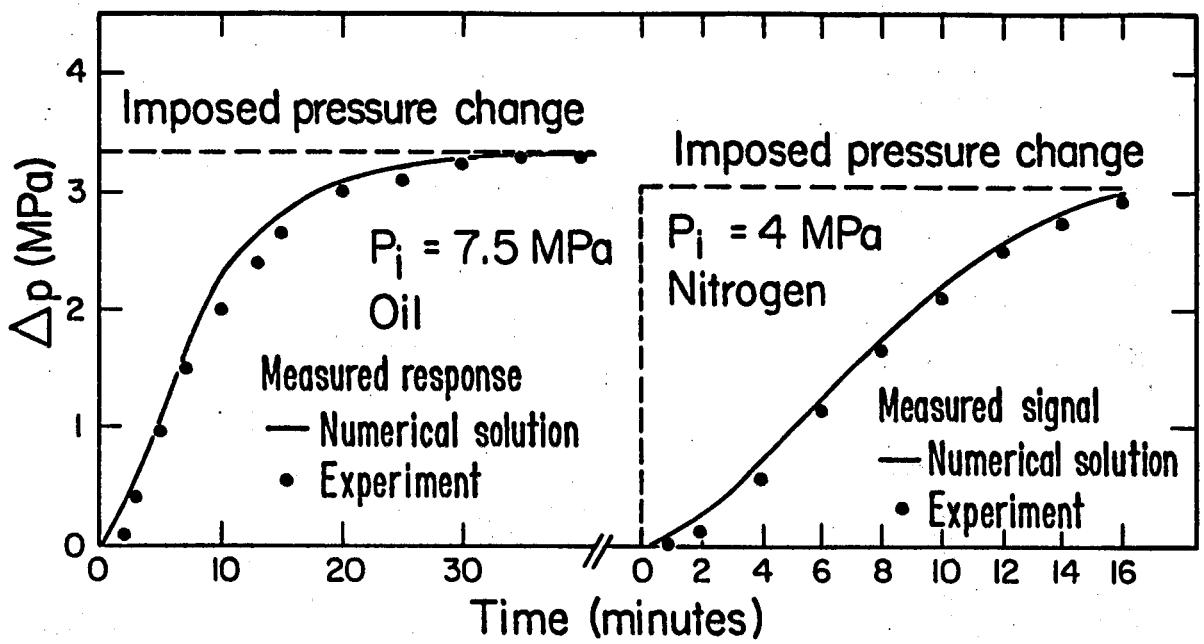
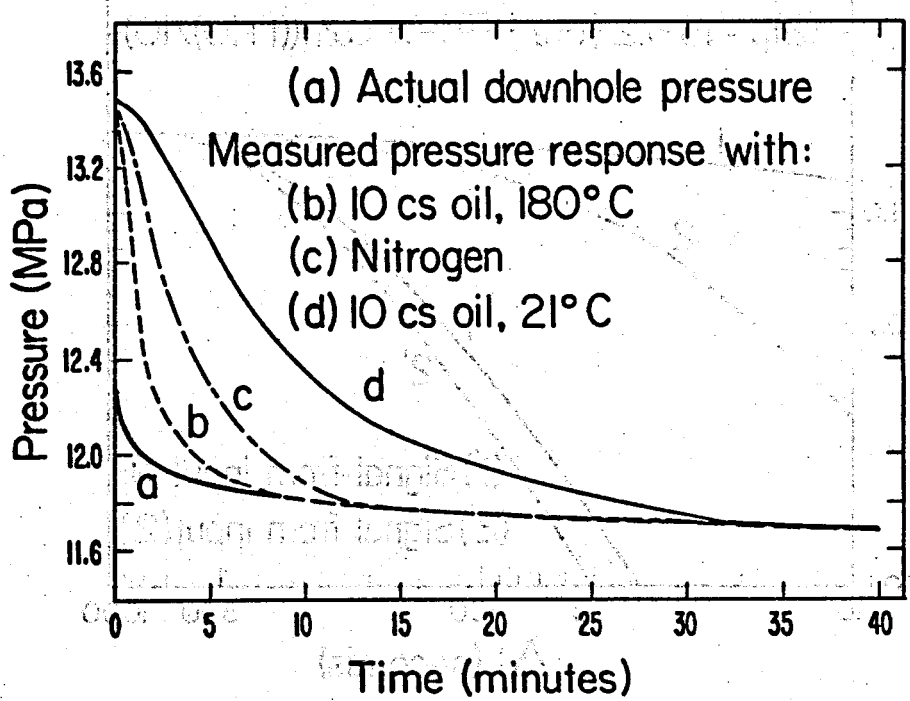


Figure 1. Schematic of downhole pressure measuring instrument



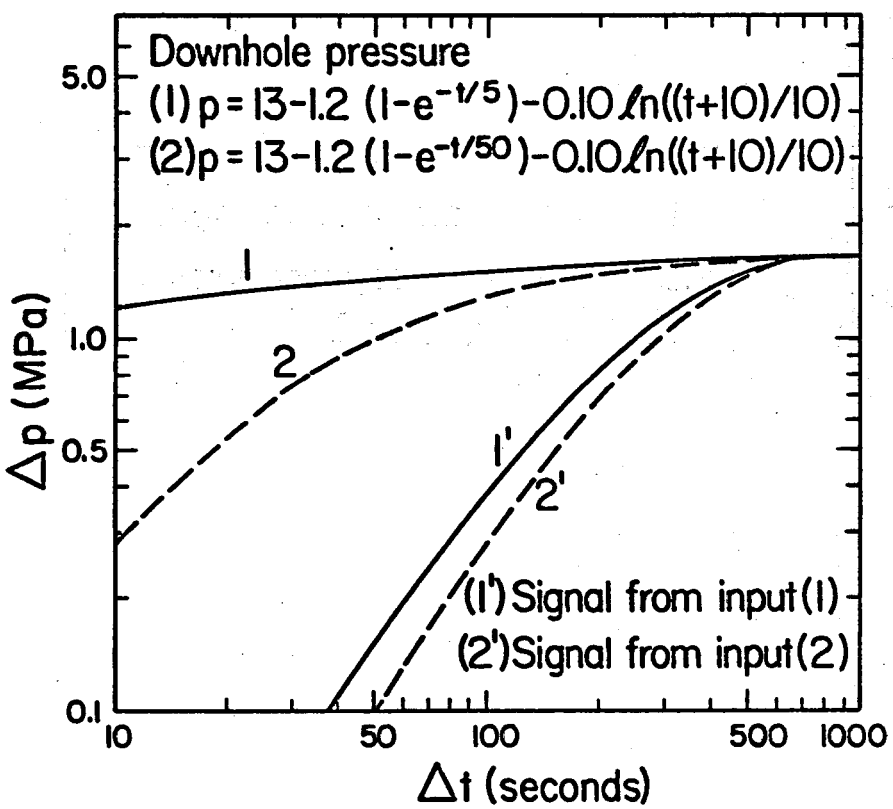
XBL 797-2061

Figure 2. Comparison of numerical calculations and experimental measurements of responses of fluid filled transmission line.



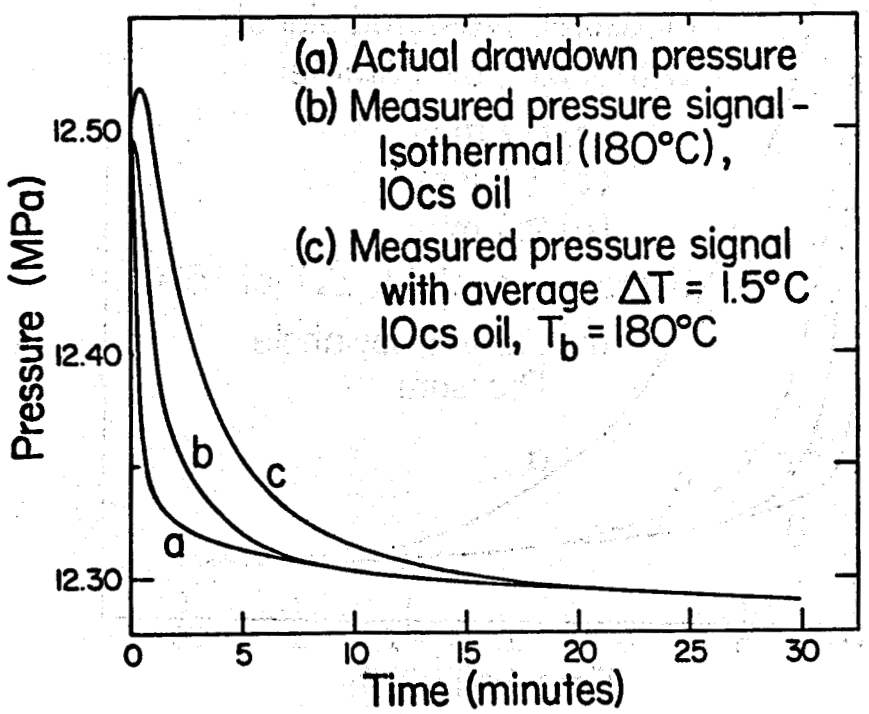
XBL 797-2063

Figure 3. Response of capillary tube to a typical drawdown signal using different fluids.



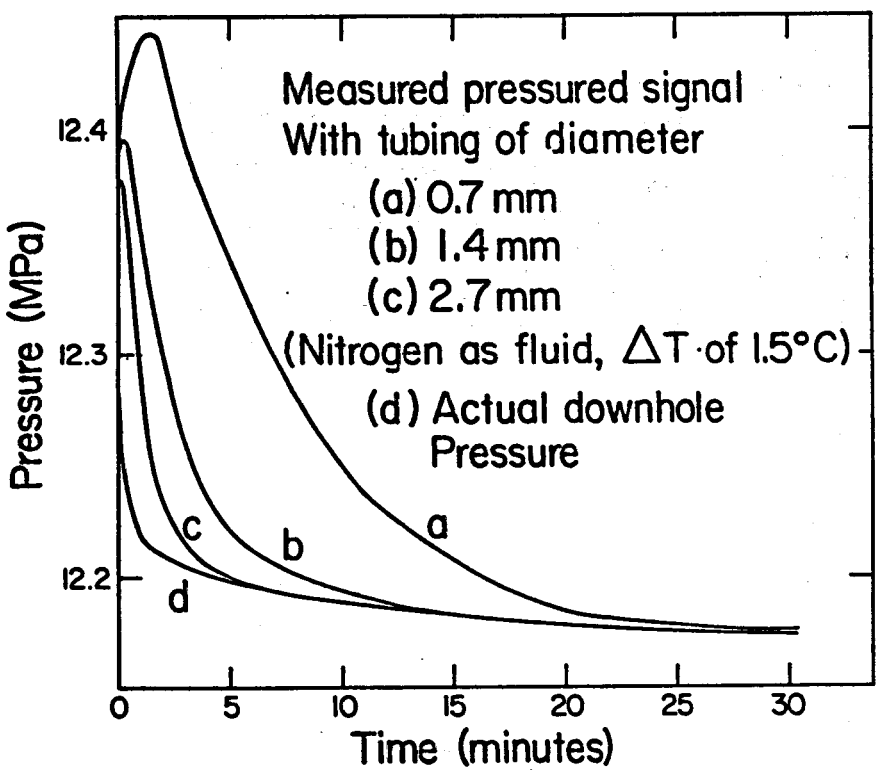
XBL 797-2062

Figure 4. Comparison of expected pressure signals for different drawdown curves; 10 cs oil at 180°C, L = 2400 m, D = .0014 m.



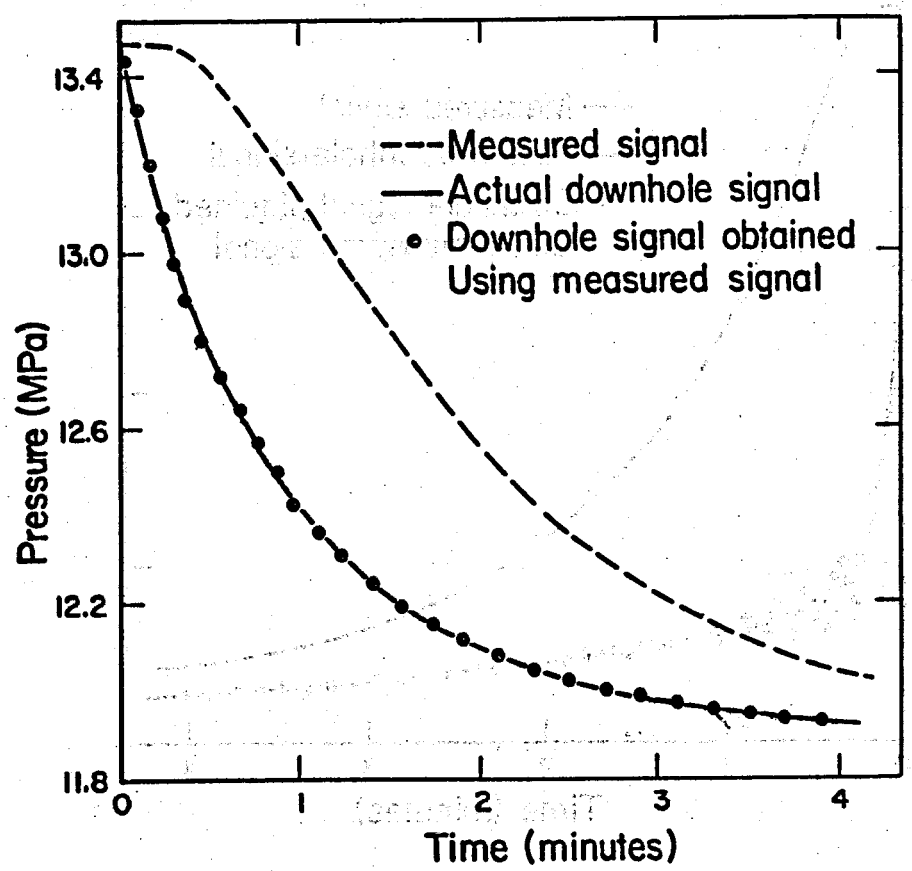
XBL 797-2065

Figure 5. Comparison of signals when transient temperature effects are important to when they are not.



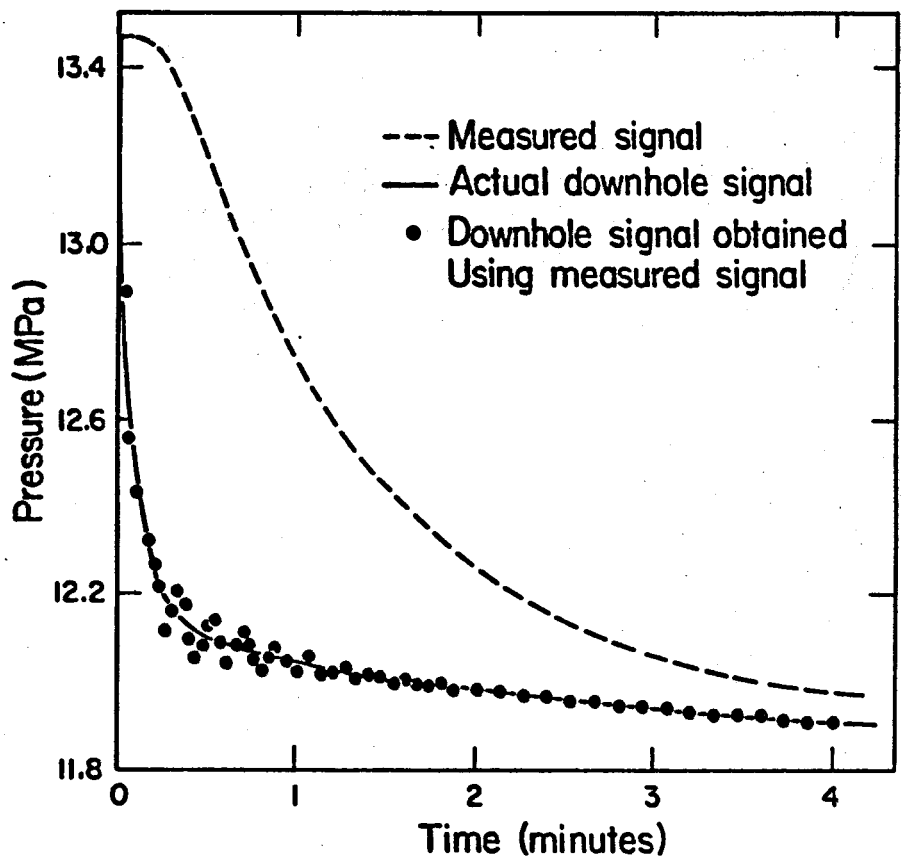
XBL 797-2064

Figure 6. Effect of different diameter tubing on the expected pressure response.



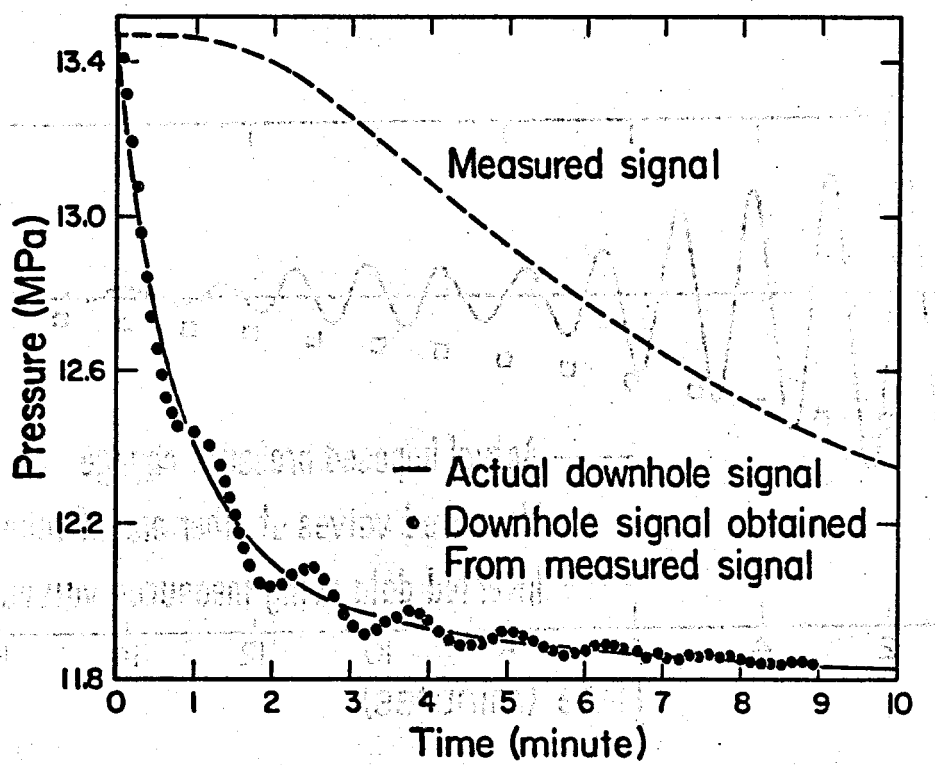
XBL 797-2060

Figure 7a. Comparison of inverted signal (calculated using measured signal) and actual simulated drawdown curve; k = 40,000 m^2/sec.



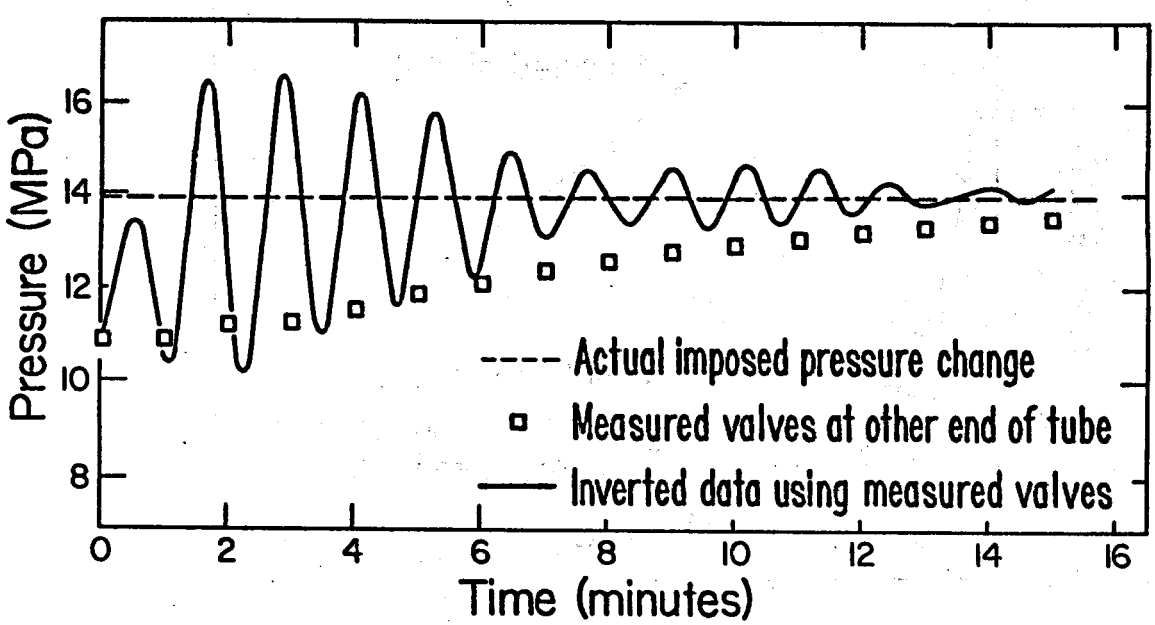
XBL 797-2058

Figure 7b. Comparison of inverted signal (calculated using measured signal) and actual downhole pressure curve, k = 40,000 m^2/sec.



XBL 797-2059

Figure 8. Comparison of inverted signal (calculated using measured signal) and actual downhole signal; α = 6,000 m^2/sec.



XBL 797-2081

Figure 9. Inversion of experimental data; α = 6,000 m^2/sec.