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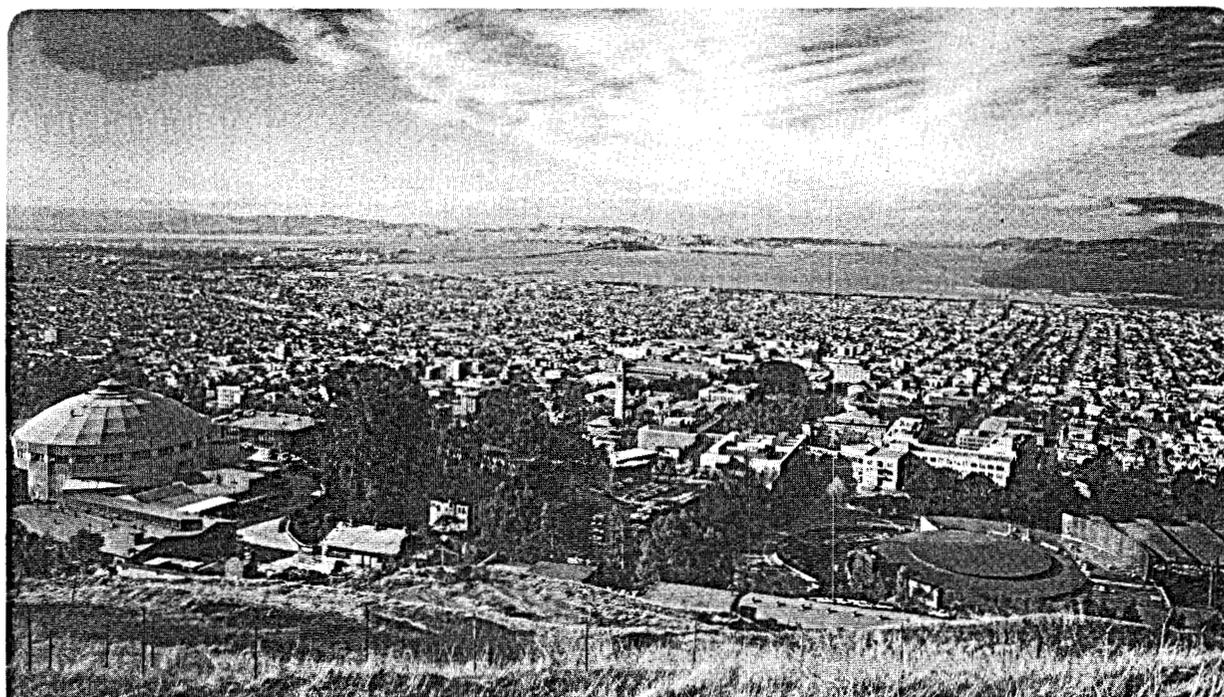
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GEOTHERMAL WELL TESTS

C.W. Miller, S. Benson, M.J. O'Sullivan, and
K. Pruess

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WELL-BORE EFFECTS IN THE ANALYSIS OF TWO-PHASE GEOTHERMAL WELL TESTS

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ABSTRACT

A method of designing and analyzing pressure transient well tests of two-phase (steam-water) reservoirs is given. Wellbore storage is taken into account and the duration of it is estimated. It is shown that the wellbore flow can completely dominate the downhole pressure signal such that large changes in the downhole pressure that might be expected because of changes in kinematic mobility are not seen. Changes in the flowing enthalpy from the reservoir can interact with the wellbore flow so that a temporary plateau in the downhole transient curve is measured. Application of graphical and non-graphical methods to determine reservoir parameters from drawdown tests is demonstrated.

INTRODUCTION

Pressure transient data analysis is the most common method of obtaining estimates of the in-situ reservoir properties and the wellbore condition. Conventional graphical analysis techniques require that for a constant flowrate well test, in an infinite aquifer, a plot of the downhole pressure vs. log time yield a straight line after wellbore storage effects are over. The slope of that line is inversely proportional to the transmissivity (kh/μ) of the reservoir. The intercept of this line with the time axis gives the $\phi C_t h (r_w^2)$ factor which is used to calculate the skin value of a well. In the present study, the effects of a two-phase steam-water mixture in the reservoir and/or the wellbore on pressure transient data have been investigated.

There have been a number of attempts to extend conventional testing and analysis techniques to two-phase geothermal reservoirs including drawdown analysis by Garg and Pritchett¹, Garg², Grant³ and Mönch and Atkinson⁴. Pressure build-up analysis has been investigated by Sorey et al.⁵. To analytically solve the diffusion equation which governs the pressure change in a two-phase reservoir, it is necessary to make a number of simplifying assumptions. One assumption is that the fluid saturation and temperature in the reservoir is initially uniform and remains uniform throughout the test. Using this approach, it can be

shown that a straight line on a pressure vs. log time plot will be obtained, the slope being inversely proportional to the total kinematic mobility (k/v_e).

When conducting a field test it is rarely possible to maintain the uniform saturation and temperature distribution in the reservoir which is required for the above type of analysis to be applicable. In addition, the very high compressibility of the two-phase fluid creates wellbore storage of very long duration. Since most of the available instrumentation for hot geothermal wells (>200°C) can only withstand geothermal environments for limited periods, long duration wellbore storage further complicates data analysis. Thus numerical simulation techniques must be used to study well tests to determine the best method of testing two-phase reservoirs.

It is the intent of this work to investigate and better define the well/reservoir system when the reservoir or wellbore is filled with a two-phase fluid. Four cases are considered: (1) a single-phase hot water reservoir connected to a partially two-phase wellbore, (2) a hot water reservoir that becomes two-phase during the test, (3) a two-phase liquid dominated reservoir, and (4) a two-phase vapor dominated reservoir. State-of-the-art analysis techniques are applied to pressure transient data obtained after wellbore storage effects have ended. In one case (case 1) a non-graphical method of analysis is discussed which is applicable at early times when wellbore storage effects still dominate the pressure response.

APPROACH

To study the pressure transient response of a two-phase geothermal well/reservoir system, a transient wellbore simulator called WELBORE⁶ was coupled to a modified version of the reservoir simulator GEOTHINZ⁷. The wellbore model does not assume steady state flow in contrast to the numerous wellbore flow models that have been reported in the literature⁸⁻¹⁰. A description of the numerical model is given in reference 6 and a brief outline of an earlier version that did not include the slip between the phases is given in reference 11. WELBORE solves finite difference approximations for the following mass, momentum, and energy balance equations:

References and illustrations at end of paper.

$$\frac{\partial \rho}{\partial t} + \frac{\partial(\rho v)}{\partial x} = 0 \quad [1]$$

$$\frac{\partial}{\partial t}(\rho v) + \frac{\partial}{\partial x} (S_v \rho_v v_v^2 + S_l \rho_l v_l^2) + \rho g + \frac{f_p v^2}{4r_w} = 0 \quad [2]$$

and

$$\begin{aligned} \frac{\partial}{\partial t}(\rho E) + \frac{\partial}{\partial x} [S_v \rho_v v_v E_v + S_l \rho_l v_l E_l] \\ + p \frac{\partial}{\partial x} [S_v v_v + S_l v_l] - \frac{u}{2r_w} (T - T_r) = 0 \end{aligned} \quad [3]$$

The slip between the phases, $v_v - v_l$, is calculated based on a modified version of that given in Orkiszewski¹². The friction factor is calculated according to Chisholm¹³. For the cases run here, conductive heat loss from the wellbore was ignored ($u = 0$).

The version of the program GEOTHNZ used here solves for radial flow only. The equations governing the mass and energy flow in a geothermal reservoir are

$$\frac{\partial}{\partial t} [\phi(S_v \rho_v + S_l \rho_l)] - \frac{1}{r} \frac{\partial}{\partial r} r(\rho_l v_l' + \rho_v v_v') = 0 \quad [4]$$

and

$$\begin{aligned} \frac{\partial}{\partial t} [(1-\phi)\rho_r C_r T + \phi(S_v \rho_v E_v + S_l \rho_l E_l)] \\ - \frac{1}{r} \frac{\partial}{\partial r} r[\rho_l H_l v_l' + \rho_v H_v v_v'] = 0 \end{aligned} \quad [5]$$

The velocities v_l' and v_v' are calculated using Darcy's law as:

$$v_l' = - \frac{k k_{rl}}{\mu_l} \frac{\partial p}{\partial r} \quad [6a]$$

$$v_v' = - \frac{k k_{rv}}{\mu_v} \frac{\partial p}{\partial r} \quad [6b]$$

For the calculations of the pressure drawdown, the relative permeability functions are assumed to have the form suggested by Corey (1954) where

$$k_{rl} = S_l^{*4} \quad [7a]$$

$$k_{rv} = (1 - S_l^{*2}) (1 - S_l^{*2})^2 \quad [7b]$$

and

$$S_l^* = (S_l - S_{lr}) / (1 - S_{lr} - S_{vr}) \quad [7c]$$

with $S_{lr} = 0.3$ and $S_{vr} = 0.05$. Finite difference

approximations of the above equations (4-7) are solved assuming that capillary pressure is negligible, the fluid and rock are in local thermal equilibrium, and conductive heat transfer is negligible.

In each of the four cases run, the calculations were carried out for a constant rate of mass production at wellhead, and for a constant rate of mass production at the sandface (no well transients considered). The pressure transient data was analyzed according to the analysis method given below. In addition, the calculated duration of wellbore storage (derived below) is compared to the time after which simulated downhole pressures with and without wellbore effects coincide.

DESIGN AND ANALYSIS OF TWO-PHASE WELL TESTS

The problem with the analysis of pressure transient data from a two-phase reservoir is that the diffusion equation describing the pressure response in the reservoir is highly non-linear. When the steam saturation varies in a porous medium, the relative flow of the water and steam phase and the compressibility of the mixture both change. For a two-phase steam-water fluid at 8MPa, the isenthalpic compressibility is about $5 \times 10^{-7}/\text{Pa}$ for high liquid saturation, it is $1 \times 10^{-7}/\text{Pa}$ for low liquid saturation, but it is only about $1.3 \times 10^{-9}/\text{Pa}$ for single phase compressed liquid at this pressure. The effective compressibility of a two-phase fluid can be enhanced by a factor of 10 or more in a porous medium due to the heat inertia of the rock¹⁴. Also, the change in the "total" kinematic viscosity, v_t , defined as

$$\frac{1}{v_t} = \left(\frac{k_{rl}}{v_l} + \frac{k_{rv}}{v_v} \right) \quad [8]$$

can be large. For relative permeability curves of the Corey type, equations 7a-7c, and at a pressure of 8 MPa, the total kinematic viscosity varies from 1.3×10^{-7} at $S_v = 0$ to 1×10^{-7} at $S_v = 0.3$, to 4.6×10^{-7} at $S_v = 1$ (using $S_{lr} = 0.3$, $S_{vr} = 0.05$). At higher pressures the variation can be greater. However, the compressibility and total kinematic viscosity are primarily a function of saturation. Therefore if one can design a test such that the pressure changes occur over a region where the saturation is relatively constant, a reasonable estimate of the transmissivity (kh/v_t) may be made.

For a reservoir that is produced at a constant mass flow rate and assuming small changes in saturation, the pressure response of the system has been shown² to be governed by the following linearized diffusion equation

$$\frac{\partial p}{\partial t} = \frac{(k/v_t)}{\phi \rho C_t} \left(\frac{1}{r} \frac{\partial p}{\partial r} + \frac{\partial^2 p}{\partial r^2} \right) \quad [9]$$

When $t > 25 \phi \rho C_t r_w^2 / (k/v_t)$, the solution to this equation is approximated by

$$p(t) = \frac{w}{4\pi(k/v_t)h} \left\{ \ln \left[\frac{(k/v_t)t}{\phi r_w^2 \rho C_t} \right] + .809 \right\} \quad [10]$$

The linearization of the non-linear diffusion equation to give equation (9) depends on the assumption that the variations in (k/v_t) , in ρ and in C_t are small. As stated above, these quantities have large variations when the steam saturation changes. When the mass flowrate from the reservoir is increased, the saturation around the bore does change if the fluid is two

phase. However, after a certain amount of time, depending on the initial saturation around the well, the in-place saturation will steady out. It is possible to treat the initial change in steam saturation in the same manner as wellbore storage is treated; namely, one needs to determine the duration for which these variations persist and to make sure all of the data analysis is performed after the changes no longer effect the data. In the case where such changes do not take place until long after the test has begun, pressure data prior to these changes can be analyzed. The problem is to determine at what times $\partial S_v / \partial r \approx 0$. Then, equation (10) can be applied and from the slope of the straight line on the p vs. $\log(t)$ plot, kh/v_c can be determined.

Using the similarity variable, $\eta = r/\sqrt{t}$, it has been shown^{5,15} that

$$\lim_{\eta \rightarrow 0} H_f / d\eta = 0 \quad [11]$$

$$\text{where } H_f = \frac{k_{rl} H_l / v_l + k_{rv} H_v / v_v}{k_{rl} / v_l + k_{rv} / v_v} \quad [11b]$$

This implies that at late times in place saturation will approach a constant value because the flowing enthalpy is primarily a function of the relative permeability curves which are in turn a function of S_v . No rigorous derivation has been done to determine when H_f can be assumed to be constant. However, O'Sullivan¹⁵ calculated S_v as a function of t/r^2 for a number of cases. An example of one of his calculations is given in Figure 1, where the liquid saturation is plotted as a function of η . For this case, $\phi = 0.2$, $k = 1 \times 10^{-13} \text{ m}^2$, $p_i = 8.6 \text{ MPa}$, $w = 0.14 \text{ Kg/s.m}$, $\rho_r = 2650 \text{ Kg/m}^3$ and $C_r = 1.0 \text{ KJ/kg K}$. The compressibility of the rock was ignored. For $S_v < 0.5$ (or $S_g > 0.5$; liquid saturation is plotted in the figure) the saturation changes are over when $t/r^2 \sim 10^3$. For high vapor saturations, the changes in saturation do not start until $t/r^2 = 10^5$ and are not over until $t/r^2 = 10^7$. A similar plot was obtained by O'Sullivan for the case where $p_i = 3.0 \text{ MPa}$, $k = 2.4 \times 10^{-13} \text{ m}^2$ and the other parameters approximately the same as above.

It is possible to estimate when S_v will be approximately constant by using the example plotted in Figure 1. The parameter t/r^2 scales approximately as $k/\phi v_c \rho C_r$. However, ρC_r is primarily a function of S_v and this variation is already taken into account in the solution. The parameter v_c is a function of the relative permeability curves used and the pressure. Corey relative permeability curves were used in this calculation. Therefore, assuming that these relative permeability curves approximately describe the steam/water flow, then it is possible to assume that one obtains the time when $H_f = \text{constant}$ by using Figure 1 and scaling t/r^2 by k/ϕ . As kh will not be known until after the pressure analysis is done, one must estimate h and calculating k , check to make sure the analysis was done for the time when $\partial S_v / \partial r = 0$. For a well of radius 0.09 m , and for a $k/\phi = 5 \times 10^{-13}$ and a reservoir pressure of 8 MPa , the changes in enthalpy were over at about 10 s for $S_v < 0.5$, while for $S_v > 0.5$, the changes occurred from 10^3 to 10^5 s . For a k/ϕ less than 5×10^{-13} , the time of these changes will be greater, and for k/ϕ greater than 5×10^{-13} , the changes will be more

rapid. Wellbore storage effects, though, can be greater or less than this time for $\partial S_v / \partial r = 0$ to hold true.

One method of testing a geothermal reservoir is to first flow the well at a slow steady rate until the saturation around the bore is approximately constant. The initial flowing of the well must be long enough so that pressure changes in the reservoir that occur during the test will penetrate only the region where the enthalpy is approximately constant. (Pritchett¹⁶ has defined a radius of investigation as $2\sqrt{Dt}$ where $D = k/\phi C_r \rho v_c$.) The flow should then be increased (or decreased) to a second constant value. By having the well flowing for a time before the test is begun, it is possible to decrease both the effect of temperature changes in the well during the test, the oscillations that occur when a well is initially opened, and to insure that $\partial S_v / \partial r \approx 0$ around the bore. Now, it is possible to do a buildup test where the well is completely shut in. However, as pointed out by Sorey et al.⁵, the region around the bore becomes saturated with liquid so S_v around the well will not be uniform, and a question arises as to how such data should be analyzed.

The state-of-the-art analysis technique for two-phase well tests has been reviewed by Pritchett¹⁶. He suggests that a drawdown, a buildup, and an injection test are needed. From the drawdown test the slope of the straight line on the plot of p vs. $\log(t)$ is measured, and from the buildup test, the slope of the straight line on the p vs. $\log[(t+\Delta t)/\Delta t]$ is determined. The transmissivity of the reservoir is calculated from the average of these two slopes (p^*),

$$\frac{kh}{v} = \frac{\Delta(w)}{4\pi p^*} \quad [12]$$

The total kinematic viscosity depends on the saturation around the bore. Pritchett does not give a method of determining the saturation. Instead he suggests that kh be measured independently by an injection test. Then given kh , the relative permeabilities can be determined from the flowing enthalpy by using

$$kk_{rl} = \left(\frac{H_v - H_f}{H - H} \right) \frac{w v_l}{4\pi p^* l} \quad [13a]$$

and

$$kk_{rv} = \left(\frac{H_f - H_l}{H - H} \right) \frac{w v_v}{4\pi p^* l} \quad [13b]$$

We find that there are several difficulties with this approach. First, many times it is neither possible or desirable to actually run an injection test. Secondly, a straight line may be seen on the semilog plot while wellbore storage is still important. For a well 2000 m deep with a radius of $.09 \text{ m}$, a $kh = 6 \times 10^{-12} \text{ m}^3$, and with two-phase flow throughout the well, wellbore storage can last on the order of 5 hours . (This neglects any storage effects of fractures.) Lastly, the duration of wellbore storage may be orders of magnitude different between a buildup and a drawdown because, in a buildup, the fluid in the well separates out into a liquid and gas phase. The compressibility of a two-phase mixture is usually larger than the compressibility of each phase separately.

Assuming that an injection test cannot be done, the following testing and analysis technique was followed in the examples. A drawdown test was simulated in all cases because it is possible to establish a region where $\partial S_v / \partial r \approx 0$ around the bore. Both the downhole pressure and the flowing enthalpy must be measured as a function of time. The downhole pressure is plotted as a function of $\log(t)$, and the transmissivity of the reservoir is determined from the slope of the straight line that is plotted in this graph. Given the value of kh/v_c , the duration of wellbore storage (ignoring fractures) is calculated to determine whether the data used in the analysis were affected by wellbore storage. An estimate of wellbore storage will be given below. Once the proper kh/v_c has been found, the kh permeability will be determined by calculating v_c .

The crucial assumption made in this part of the analysis is that we know the relative permeabilities as a function of S_v . The flowing enthalpy permits us to determine the ratio of relative permeabilities for water and steam

$$\frac{k_{rL}}{k_{rV}} = \frac{v_L (H_v - H_f)}{v_V (H_f - H_L)} \quad [14]$$

In writing down equation 14 it was assumed that $k_{rV} \neq 0$. If the pressure is known, v_L , H_L , v_V , H_V will be known. If k_{rL} and k_{rV} are given as a function of S_v , then, knowing H_f , the saturation can be determined. Figure 2 is a plot of H_f vs. S_v for $p = 4.5$ MPa using k_{rL} and k_{rV} as given by equations 7a-7c. Since k_{rL} and k_{rV} are known, v_c can be calculated as well as the absolute permeability thickness, kh .

If the relative permeability functions are not known, two lower estimates for kh can be made. Using equations 13a, 13b, khk_{rL} and khk_{rV} can be computed, both of which will be smaller than kh . However, usually not both k_{rL} and k_{rV} will be much less than one so that the larger of the two quantities khk_{rL} and khk_{rV} will provide an estimate for kh itself.

For all of the cases calculated here, the Corey relative permeability curves were used. In one case (case 3) the effect of using other permeability curves was investigated. It is recognized that relative permeability curves for steam-water mixtures are not well known. It is also recognized that they may be dependent on the rock type in which a geothermal resource occurs. Our point is that if these relative permeability curves were better known, a plausible methodology for obtaining the in situ reservoir parameters is available. It is stressed that more work is necessary to obtain these curves.

DURATION OF WELLBORE STORAGE

As stated above, wellbore storage phenomena in two-phase geothermal well/reservoir systems can last for several hours. The duration of wellbore storage is proportional to both $(\partial \rho / \partial p)_E$ and $(kh/v_c)^{-1}$. Because the transmissivity of geothermal reservoirs is usually greater than the transmissivity of oil/gas formations, wellbore storage in liquid filled reservoirs tends to be shorter than in hydrocarbon reservoirs. However, for two-phase geothermal reservoirs,

the compressibility effects of the steam-water mixture in the wellbore are an order of magnitude larger than oil and gas systems because of phase transition effects. In addition, wellbore storage calculations in the petroleum literature neglect energy changes in the well. We will define both an isenthalpic and an isobaric wellbore storage term. The wellbore storage phenomenon persists until both of the above wellbore storage contributions have become negligibly small.

Wellbore storage is over when the sandface flowrate is approximately equal to the surface flowrate. For an isothermal well, Ramey¹⁷ determined that when $t_D > 60 C_D$, the effects of wellbore storage can be neglected. We will assume a similar formulation to estimate the isenthalpic wellbore storage time by defining an average isenthalpic compressibility in the wellbore. The isobaric wellbore storage term will be determined by calculating when energy changes in the well are over. However, heat loss out of the bore will be ignored although it can be important.

For a change in mass flowrate at wellhead, the sandface mass flowrate can be calculated by using the continuity equation and by integrating it over the length of the well.

$$\int_0^L \frac{\partial \rho}{\partial t} dx = - \int_0^L \frac{\partial}{\partial x} (\rho v) dx = \frac{-w_s + w_{sf}}{A}$$

or

$$w_{sf} = w_s + A \int_0^L \frac{\partial \rho}{\partial t} dx \quad [15]$$

Changes in density in the well are a function of pressure and energy. Rewriting $\partial \rho / \partial t$ in terms of p and E , equation (15) is written as

$$w_{sf} = w_s + A \int_0^L \rho C_E \frac{\partial p}{\partial t} dx + A \int_0^L \rho \beta \frac{\partial E}{\partial t} dx \quad [16]$$

where $C_E = \frac{1}{\rho} \left(\frac{\partial \rho}{\partial p} \right)_E$ and $\beta = \frac{1}{\rho} \left(\frac{\partial \rho}{\partial E} \right)_p$. The duration of energy and pressure changes will be estimated separately.

The difference in wellhead and the downhole mass flowrate due to pressure changes only is

$$w_{sf} = w_s + A \int_0^L \rho C_E \frac{dp}{dt} dx, \quad [17]$$

where C_E and p are functions of x . However, as wellbore storage dies out, dp/dt will be a very weak function of x and it is possible to rewrite equation (17)

$$w_{sf} = w_s + \frac{dp}{dt} A \int_0^L \rho C_E dx. \quad [18]$$

If the wellbore storage coefficient is defined as

$$\bar{C} = \frac{1}{L} \int_0^L \rho C_E dx = \frac{1}{L} \int_0^L \left(\frac{\partial \rho}{\partial P} \right)_E dx \quad [19]$$

then equation (18) can be written as in the petroleum literature

$$w_{sf} = w_s + \bar{C} \frac{dP}{dt} \quad [20]$$

$$\text{Defining } C_D = \frac{\bar{C}}{\rho_{sf} 2\pi \phi C_{tR} h r_w^2} \text{ and } t_D = \frac{kt}{\rho_{sf} \phi C_{tR} v_t r_w^2}$$

and assuming that the effects of wellbore storage on the downhole pressure changes will be over when $t_D > 60C_D$, then

$$t_H = 60 \frac{\bar{C}}{(2\pi) kh/v_t} \quad [21]$$

The factor kh/v_t is measured directly from the slope of the p vs. $\log(t)$ plot and given the steady state initial conditions in the well, the average value of $(\partial \rho / \partial p)_E$ in it can be determined. Note it is $(\partial \rho / \partial p)_E$ and not $(1/\rho)(\partial \rho / \partial p)_E$ which is averaged in the bore.

There may be some question as to whether one should use $(\partial \rho / \partial p)_E$ or $(\partial \rho / \partial p)_H$ or something else. Garg and Pritchett¹ have shown that $(\partial \rho / \partial p)_E / \rho$ and $(\partial \rho / \partial p)_H / \rho$ can vary by a factor of 2 at high pressure when the fluid is compressed liquid. However in the two-phase region no large variations occur in contrast to what one might expect. It is possible to show that

$$\left(\frac{\partial \rho}{\partial p} \right)_H = \frac{(\partial \rho / \partial p)_E - \frac{1}{\rho} (\partial \rho / \partial E)_p}{1 - \frac{p}{\rho} \left(\frac{1}{\rho} \frac{\partial \rho}{\partial E} \right)_p}$$

In the two phase region $(\partial \rho / \partial p)_E$ is much larger than $(\partial \rho / \partial E)_p / \rho$ while in the compressed liquid region these terms are more comparable. Therefore, as an estimate for two-phase wellbore storage, one can use either $(\partial \rho / \partial p)_E$ or $(\partial \rho / \partial p)_H$.

For the changes due to any energy increases or decreases in the well, the continuity equation is

$$w_{sf} = w_s + A \int_0^L \rho \beta \frac{dE}{dt} dx.$$

Wellbore storage due to energy changes will be over when $dE/dt \approx 0$. If the heat loss out of the bore is ignored, then

$$\rho \frac{\partial E}{\partial t} \approx \rho v \frac{\partial H}{\partial x}$$

As long as there is a significant change in the flowing enthalpy from the reservoir, wellbore storage effects will persist. However, once H_f is approximately constant, then the additional time for the energy changes in the well to steady out is just the time for a particle to travel through the wellbore or L/v_{ave} . This average velocity is defined as

$$v_{ave} = \frac{\int_0^L \rho v dx}{\int_0^L \rho dx} = \frac{\bar{\rho v}}{\bar{\rho}}$$

If $\rho v \approx w_s/A$, then $v_{ave} \approx w_s/A\bar{\rho}$. However if ρv is still varying in the well then a more conservative estimate would be to use w_{sf}/A for ρv .

Wellbore storage effects will persist until

$$t > \frac{60\bar{C}}{2\pi kh/v_t}$$

or until $t > L/v_{ave}$ after the flowing enthalpy is constant from the reservoir which ever is greater. In all the analyses done below, a check will be done to determine if wellbore storage is over.

EXAMPLE

To consider the effects of the wellbore flow on the testing of geothermal reservoirs and to consider methods of determining the permeability of such reservoirs; four different examples were considered. (See Table 1 for the initial conditions.) For all the cases run, $k = 3 \times 10^{-14} \text{ m}^2$, $h = 80 \text{ m}$, $\phi = 0.15$, $C_T = 1.0 \text{ kJ/kg K}$ and $\rho_r = 2000 \text{ Kg/m}^3$. The viscosity of the liquid and steam phases were calculated with

$$\mu_L = 2.414 \times 10^{-5} \times \left[10^{247.8/(T+133.15)} \right] \text{ Pa.s}$$

$$\mu_V = (9 + .035T) \times 10^{-6} \text{ Pa.s}$$

respectively⁷.

A drawdown pressure transient test was simulated by first flowing the well/reservoir system for 24 hours at 5 kg/s. (The flowing enthalpy, pressure, and vapor saturations at the sandface after this initial 24 hours are also given in Table 1.) Subsequently the flowrate was increased from 5 to 30 kg/s in the first two cases and from 5 to 15 kg/s in cases 3 and 4. The drawdown test was then run up to 10 hours. Both a constant flowrate at wellhead and a constant flowrate at the sandface were considered. When the well flow was included, the well was assumed to be 2000 m deep with a radius of 0.09 m. Both skin effects and heat loss from the wellbore were ignored although they both can influence well test transient data. Table 2 summarizes the calculations.

For all the examples, the following method of analysis was followed. First the average value of the compressibility density term, ρ_{CH} , was computed at the flowing conditions in the well before the flowrate was increased. Then the slope of the straight line segment on the plot of the p_{dh} vs. $\log(t)$ was measured. The limits of the time over which this straight line segment was chosen is listed in Table 2, where t_1 is the time for the beginning of the segment and t_2 is the end of the segment. Note that two analyses were done for both examples 2 and 3 to illustrate the error in kh if the wrong straight line is chosen.

Using the measured slope, the transmissivity, kh/ν_t , and the duration of the isenthalpic wellbore storage effect (using equation 21 and designated by t_H in Table 2) were calculated. The duration of wellbore storage because of energy changes during the test is best determined by monitoring the flowing enthalpy. However, a very rough estimate can be made by assuming that it persists for a time equal to L/v_{ave} after the enthalpy from the reservoir is constant. A rough estimate of the time when these energy changes are important is given in the table and designated t_p . If the straight line segment chosen occurs while wellbore storage was important, the calculation of kh/ν_t should be repeated using the correct line segment.

Now, given the flowing enthalpy and downhole pressure at some point along the straight line segment, and assuming Cory relative permeability curves, when the fluid is two-phase in the reservoir, the vapor saturation around the bore was calculated. Given this S_v , the total kinematic viscosity, ν_t , was computed and in turn kh was determined. The computed values for kh were compared to the kh of $2.4 \times 10^{-12} m^3$ used in the actual simulation (see Table 2).

HOT WATER RESERVOIR

The first case considered is a hot water reservoir, where the fluid flashes in the bore during the well test. The downhole transient pressure after the increase in mass flowrate to 30 kg/s, is given in Figure 3. Results for both the constant flowrate at wellhead and at the sandface are plotted. The calculation for kh gave $2.6 \times 10^{-12} m^3$ and the isenthalpic wellbore storage lasted 3.2×10^3 s (54 minutes). The calculation for the time until energy changes can be neglected is just the time for a fluid particle to travel through the bore. Because the fluid flowing from the reservoir remains single phase, the flowing enthalpy at the sandface is constant. In the pressure drawdown simulation, when the flowrate was increased, the wellhead enthalpy decreased initially and then increased back to the enthalpy before the flowrate change. A conservative estimate for the time is $VP/(w_{sf})_i$ or 60 minutes in this case ($\bar{\rho} \approx 400$ kg/m³).

Because the analysis for kh was done after the end of wellbore storage, excellent agreement was obtained between the calculated kh ($2.6 \times 10^{-12} m^3$) and the actual kh ($2.4 \times 10^{-12} m^3$) used in the simulation. It is also possible to calculate $\phi C_t h r_e^2$ for this case. Using the intercept of the straight line segment with $t = 1$ s, $\phi C_t h r_e^2$ was computed as $1 \times 10^{-10} m^3/Pa$. The value used for the simulation was $1.45 \times 10^{-10} m^3/Pa$. The difference

between these numbers occurs because the finite grid used around the wellbore introduces a slight skin effect.

In many cases, because of the high flowrate and high temperatures in a geothermal well, it is difficult to keep tools downhole for extended periods of time. Many tests cannot even be run for one hour, and as we see from this case, wellbore storage is not over until one hour. To obtain a good estimate of kh , the test would have to be run at least ten hours. Data from a shorter test can only be analyzed if proper allowance is made for the change of sandface flowrate with time.

If the fluid in the reservoir remains single phase, the reservoir parameters, kh/μ and $\phi C_t h r_e^2$ can be calculated even when the sandface flowrate is varying as long as this flowrate is known. It is possible to solve for this sandface flowrate if both the wellhead flowrate and the downhole pressure are measured. However a transient wellbore simulator must be used for this calculation. It is not possible to use some average compressibility in the well and then compute that the mass exiting the bore is $\rho C(dp_{dh}/dt)$. No one pressure measurement is characteristic of the average pressure change in the bore. If the transient pressure change in the bore were independent of position, then the initial slope of a $\log \Delta p$ vs. $\log(t)$ plot would be unity as derived in the petroleum literature. Plotted in Figure 4 is $\log \Delta p$ vs. $\log(t)$ for this first case. We see that the initial slope of the plot is greater than 1 indicating that the transient pressure changes in the bore are a function of position. The change in pressure made at wellhead takes about 20 s to "arrive" downhole after which the downhole pressure rises abruptly. (More detailed discussion of this phenomena is given in ref. 11) The pressure response approaches the downhole pressure change expected when dp/dt is not a function of position. The average compressibility of the fluid in the well is changing also during the test. Therefore a transient wellbore flow model must be used to obtain the sandface flowrate.

Using the simulator WELBORE, the actual sandface flowrate can be calculated. Wellbore effects can be eliminated, allowing reservoir properties to be determined from a variable rate analysis technique. We have done this using a computer program called ANALYZE¹⁸. This program performs history matching for pressure transient data of a system of wells, based on the Theis solution. It uses a least squares technique to minimize the difference between a set of measured pressure points and a set of calculated pressure points. The calculated pressure points are generated by varying the transmissivity (kh/μ) and the storativity ($\phi C_t h$) (or given $\phi C_t h$, the skin is varied).

The program is designed for the analysis of interference and production tests in single phase, fluid-saturated hydrothermal reservoirs. It is used to analyze data from just one production well in this case. Given the sandface flowrate for the first 15 minutes (calculated with the wellbore simulator), the sandface flow and the downhole pressure where input to the program ANALYZE. Figure 5 shows both the actual sandface flowrate and the downhole pressure as a function of time. Included on the figure are the calculated pressures after a best fit was obtained. The best fit gave a $kh/\mu = 2.8 \times 10^{-8} m^3/Pa.s$ and

a $\phi C_t h r_e^2 = 7 \times 10^{-9} \text{ m}^3/\text{Pa}$. (Again, the values used in the simulation were $2.7 \times 10^{-8} \text{ m}^3/\text{Pa}\cdot\text{s}$, $\phi C_t h r_e^2 = 1.45 \times 10^{-9} \text{ m}^3/\text{Pa}\cdot\text{s}$). This later quantity is a good fit considering that it is very sensitive to errors. The result for kh/μ is quite accurate. Note that the pressure data for this first 15 minutes would be useless without such a technique for evaluating time dependent sandface flow due to wellbore storage as wellbore storage is not over for 60 minutes. The pressure data from 10^2 to 10^3 s plots as a fairly straight line. If no data were taken afterwards, the subsequent change in slope would not be noticed. If this data were mistakenly analyzed assuming constant sandface flowrate, the kh/μ value obtained would only be $6.5 \times 10^{-9} \text{ m}^3/\text{Pa}\cdot\text{s}$. The value for $\phi C_t h r_e^2$ would be several orders of magnitude off, on the order of 1.4×10^{-7} . Because of the limit at present on the time of keeping a tool downhole in a geothermal field, a method for evaluating time-dependent sandface flowrates is of great practical value, as it allows good estimates of kh/μ and $\phi C_t h r_e^2$ to be made from short tests.

HOT WATER RESERVOIR WITH FLASHING

In the second example, the initial reservoir pressure was lowered somewhat so that flashing around the well would occur during the well test. The pressure drawdown in this case is given for a constant sandface flowrate and a constant wellhead flowrate in Figure 6. For the former case, the pressure drawdown follows the single phase case until the first grid block starts to flash (at about 150 s). At 250 s, the next block flashes and the pressure begins to drop at a faster rate because of the decrease in the total kinematic mobility. Small oscillations about the average of drawdown curve occur because of finite space discreteness. This is a well known effect, which can be diminished by using a finer grid.

The second case (constant wellhead flowrate) given in the figure shows that the downhole pressure does not start to drop until after 20 s. (The propagation of a disturbance through the compressible two-phase mixture in the wellbore is slow.) For this particular case, a straight line is obtained from 10^2 to 10^4 s, and the change in slope of the drawdown curve when the reservoir begins to flash is completely masked now. Also the oscillations that occurred in the calculation with constant sandface flowrate are damped out by the well. (The same grid was used in both cases). It is not possible to rely on changes in the downhole pressure to predict when flashing begins in the reservoir during a test. Measurements of the flowing enthalpy with the downhole pressure are needed to detect flashing in the bore.

For this case, it is very important to determine the duration of wellbore storage. One might be tempted to use the slope of the line from 10^2 to 10^4 s. Although the calculated value of kh/V_t might not be far off, the determination of kh would be inaccurate as seen in Table 2.

The flowing enthalpy needed to determine v_t varies considerably when the fluid first starts to flash in the reservoir. If the test was run only one hour, the calculation for kh gives $1.2 \times 10^{-12} \text{ m}^3$, only half of the actual value used in the simulation. The second analysis for kh for this case 2 given in the table shows that a more reasonable value of kh is obtained ($2.8 \times 10^{-12} \text{ m}^3$) when the analysis is

done after wellbore storage is over (1.1×10^4 s). The calculations for $kh_{k_{rl}}$ and $kh_{k_{rv}}$ give the lower estimate on kh .

A check must be done to insure that the energy changes in the bore are negligible. However, because flashing in the reservoir can occur at any time during the test in this case, the best method is to actually monitor the wellhead enthalpy until it steadies out. No estimate was made for this time for this example.

LIQUID DOMINATED TWO-PHASE RESERVOIR

The third example is a liquid dominated but two-phase reservoir. Before the initial 24 hours drawdown, the initial steam saturation was 0.19. After the 24 hours, the average saturation around the bore out to approximately 10 m is 0.29. When the flowrate is increased to 15 kg/s, the vapor saturation increases to about 0.4. It is evident from the test it would be hard to determine the in-place vapor saturation because the testing itself changes the saturation conditions in the reservoir.

When the flow from the reservoir is increased, the enthalpy from the reservoir increases. However, there is usually a slight delay depending on the conditions in the reservoir. Therefore, the downhole pressure starts to drop while the enthalpy of the fluid entering the well remains fairly constant. The sandface flowrate is slowly increasing. However, once the flowing enthalpy starts to increase, the interaction of this flow with the wellbore fluid flow produces a very interesting phenomenon illustrated in Figure 7. The pressure drops until the flowing enthalpy into the well starts to increase. At this point, because the energy in the bore is increasing, the amount of mass that can be taken from the bore increases. Because less mass must come from the reservoir to keep a constant mass at wellhead, the downhole pressure stops dropping and remains on a plateau until the flowing enthalpy from the reservoir steadies out. Subsequently, more fluid must come from the reservoir, so that downhole pressure starts to drop again. However, wellbore storage is not necessarily over yet as only the energy changes are negligible. It is still necessary to calculate the isenthalpic wellbore storage term.

Again two analyses were done for this example as given in Table 2. In one case, the analysis was done for the time period from 1×10^3 to 3×10^3 . However, wellbore storage was estimated to last at least 6.2×10^4 s with this analysis. The calculated kh gave a very low value ($6 \times 10^{-13} \text{ m}^3$). When the second analysis was done at the later times, the calculation for kh was closer ($2.9 \times 10^{-12} \text{ m}^3$) to that actually used.

The analysis shown in Table 2 used Corey relative permeability curves. The calculation for kh using alternate relative permeability curves was also done for this example. Table 3 summarizes the calculations for the Corey relative permeability curves with two different irreducible liquid saturations, the straight line relative permeability curves ($k_{rl} = 1 - S_v$, $k_{rl} + k_{rv} = 1$), Grant's curves¹⁹ ($k_{rl} = S_v^{*4}$ where S_v^* is given by equation 7c, $k_{rl} + k_{rv} = 1$) and the extrapolated curves²⁰ of Council and Ramey²¹ ($k_{rl} = 1 - S_v/0.3$ for $S_v < 0.3$, otherwise $k_{rl} = 0$, $k_{rv} = (S_v - 0.2)/0.8$ for $S_v > 0.2$, $k_{rv} = 0$ for $S_v < 0.2$.) We see that different

values of the irreducible liquid saturation with the Corey curves does not affect the analysis. Also both the straight line permeability curves and Grant's curves give similar results for this case. However, there is a very large difference in the calculation for kh when the different relative permeability curves are assumed. We conclude that for an accurate estimation of kh when injection testing cannot be done, some reasonable estimate of what relative permeability curves apply is important.

A buildup case was also simulated for this example and the downhole pressure change is plotted in Figure 9. The pressure change is greater than for the drawdown case because the change in flowrate was from 15 to 0 kg/s while in the drawdown case it was from 5 to 15 kg/s. What should be noticed from this graph is that wellbore storage seems to last a much shorter time for a buildup than for a drawdown test. When the well is shut in, the steam and liquid phases separate out in the bore. The compressibility of each phase is much less than the compressibility of a well dispersed two-phase mixture. Phase changes occur easier in the two phase mixture resulting in a longer wellbore storage phenomenon. However, it is difficult to analyze a buildup data, when the fluid is two phase in the reservoir because the liquid forms at the bottom of the well and the liquid saturation around the bore is 100%. Small amounts of liquid can flow from the well back into the reservoir during the buildup test. Although the buildup test may look more desirable, it is very hard to determine v_t when S_v around the bore is such a strong function of position.

VAPOR DOMINATED TWO-PHASE RESERVOIR

In the fourth example, an initial steam saturation of 0.78 was assumed. After 24 hours of production, the steam saturation varies between 0.7 and 0.82 around the bore. As indicated above (Figure 1), when the steam saturation is high, changes in enthalpy can occur at very late times. It would probably have been better to initialize this case for a longer time.

Figure 10 is a plot of the drawdown pressure vs. time both considering the wellbore flow and neglecting it. At these high initial saturations and using Corey relative permeability curves, only steam flows in the well. The average compressibility in the well is much less than in the other cases. The isenthalpic contribution to wellbore storage only lasts 650 s and the test need only be run for one hour.

Over the time span that kh/v_t was calculated, K_p is approximately constant indicating that energy changes in the well/reservoir are not important. However, at about 7×10^3 s, the drawdown curve suddenly starts dropping at a greater rate. A check of the flowing enthalpy shows that some liquid is starting to flow. The liquid saturation around the bore is now greater than the assumed irreducible liquid saturation (0.3 here). Condensation occurs around the bore when the system is initially at a pressure that is above the maximum steam enthalpy point as in this case. To analyze the drawdown curve after 7×10^3 s, it is necessary to wait until the flowing enthalpy from the reservoir steadies out.

CONCLUSION

A geothermal reservoir simulator and a transient wellbore model have been coupled to generate a series of drawdown histories for various types of two-phase reservoirs. Estimates of wellbore storage times have been made. Pressure decline curves have been analyzed with analytical methods and with computerized curve-matching for variable flowrates. The following results have been obtained.

- (1) Wellbore storage effects in two-phase drawdown tests can last for several hours, during which time the pressure response is controlled by the variable sandface flowrate. However, in contrast to oil and gas wells, the sandface flowrate does not always approach the surface flowrate in a monotonic way producing a temporary plateau in the downhole pressure transient curve.
- (2) Monitoring of the flowing wellhead enthalpy is essential for meaningful results.
- (3) If the drawdown test is appropriately designed, pressure transients are governed by a linear diffusion equation and a determination of the total kinematic mobility can be made.
- (4) A transient wellbore model allows for an evaluation of the total kinematic mobility from short time tests which are dominated by wellbore storage effects.
- (5) The ratio of relative permeabilities for water and steam, k_{rl} and k_{rv} , can be determined as a function of flowing enthalpy.
- (6) Absolute permeability thickness and the in-place vapor saturation around the wellbore during the test can be obtained if the relative permeabilities are known as a function of saturation or alternatively;
- (7) the relative permeability curves can be determined if the absolute permeability and in-place saturation are known.

NOMENCLATURE

A	= area of wellbore
C_t	= total compressibility of reservoir
C	= isenthalpic compressibility, $(1/\rho)(\partial\rho/\partial p)_H$
C_E	= compressibility, $(1/\rho)(\partial\rho/\partial p)_E$
C_r	= heat capacity of rock
E	= specific energy
f	= friction factor
h	= reservoir thickness
F	= specific enthalpy
k	= permeability
k_{rl}	= relative permeability of liquid water
k_{rv}	= relative permeability of steam
L	= length of wellbore
p	= pressure
p^*	= slope of p vs. log (t) plot
r_w	= wellbore radius
r_l	= effective wellbore radius
r	= radial distance
s	= skin
S	= saturation
S_{lr}	= irreducible liquid saturation
S_{lv}	= irreducible steam saturation
t	= time

T = temperature
 u = heat transfer coefficient
 v = mass averaged velocity
 v_A' = Darcy liquid velocity
 v_V' = Darcy steam velocity
 w = mass flowrate
 x = axial distance

GREEK

β = $(1/\rho)(\partial\rho/\partial E)p$
 η = r/t
 ϕ = porosity
 ρ = density
 μ = absolute viscosity
 ν = kinematic viscosity
 ν_t = total kinematic viscosity

SUBSCRIPT

dh = downhole
 f = flowing
 i = initial
 l = liquid
 r = rock
 sf = sandface
 s = surface
 v = vapor

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TABLE 1 - Initial conditions and downhole conditions after twenty-four hours of production for the four examples.

	Case 1	Case 2	Case 3	Case 4
p_i (MPa)	12.70	11.1	10.0	10.0
p_{24} (MPa)	12.34	10.74	8.94	9.26
H_i (MJ/kg)	1.400	1.400	1.433	1.700
$(H_f)_{24}$ (MJ/kg)	1.400	1.400	1.566	2.736
$(S_v)_i$	0	0	0.19	0.78
$(S_v)_{24}$	0	0	0.29	0.70-0.82
$(w_g)_i$ (Kg/S)	5	5	5	5
$(w_g)_f$ (Kg/S)	30	30	15	15

TABLE 3 - Analysis of pressure transient data for case 3 using different relative permeability curves.

	Cory ($S_{LR}=0.3$)	Cory ($S_{LR}=0.7$)	Straight Line	Grants	Council and Ramey
S_v	0.42	0.19	0.89	0.33	0.296
k_{rL}	0.034	0.033	0.11	0.12	0.01
k_{rV}	0.26	0.270	0.89	0.88	0.12
$1/v_T$	5.9×10^5	5.9×10^5	1.9×10^6	2.0×10^6	2.2×10^5
kh	2.9×10^{-12}	2.9×10^{-12}	8.75×10^{-13}	3.5×10^{-13}	7.5×10^{-12}

TABLE 2 - Analysis of pressure transient data

	Case 1	Case 2	Case 2	Case 3	Case 3	Case 4
\overline{pc} (s^2/m^2)	1.3×10^{-4}	1.1×10^{-4}	1.1×10^{-4}	6.0×10^{-5}	6.0×10^{-5}	8.0×10^{-6}
t_1 (s)	3,000	300	10,000	1,000	10,000	700
t_2 (s)	30,000	3,000	30,000	3,000	30,000	7,000
$\frac{kh}{v_t}$ (m.s ²)	2.0×10^{-5}	4.1×10^{-6}	5.0×10^{-6}	4.7×10^{-7}	1.7×10^{-6}	6.0×10^{-6}
t_H (s)	3,200	12,000	11,000	62,000	17,000	650
H_P (MJ/kg)	1.40	1.39	1.41	2.03	2.06	2.75
p (MPa)	10.8	9.3	7.8	6.7	4.5	8.0
T (C)	310	305	293	282	257	295
S_v	0	0.18	.26	.40	0.42	0.7-1.0
khk_{rL} (m ³)	---	---	1.0×10^{-12}	---	5.6×10^{-13}	4.2×10^{-15}
khk_{rV} (m ³)	---	---	1.7×10^{-13}	---	7.7×10^{-13}	2.7×10^{-12}
t_p (s)	0-3600	---	---	---	0-3600	$2 \times 10^3 - 2 \times 10^5$
v_T (m ² /s ²)	1.3×10^{-7}	3.0×10^{-7}	5.6×10^{-7}	1.3×10^{-6}	1.7×10^{-6}	4.9×10^{-7}
kh (m ³)	2.6×10^{-12}	1.2×10^{-12}	2.8×10^{-12}	6×10^{-13}	2.9×10^{-12}	2.9×10^{-12}

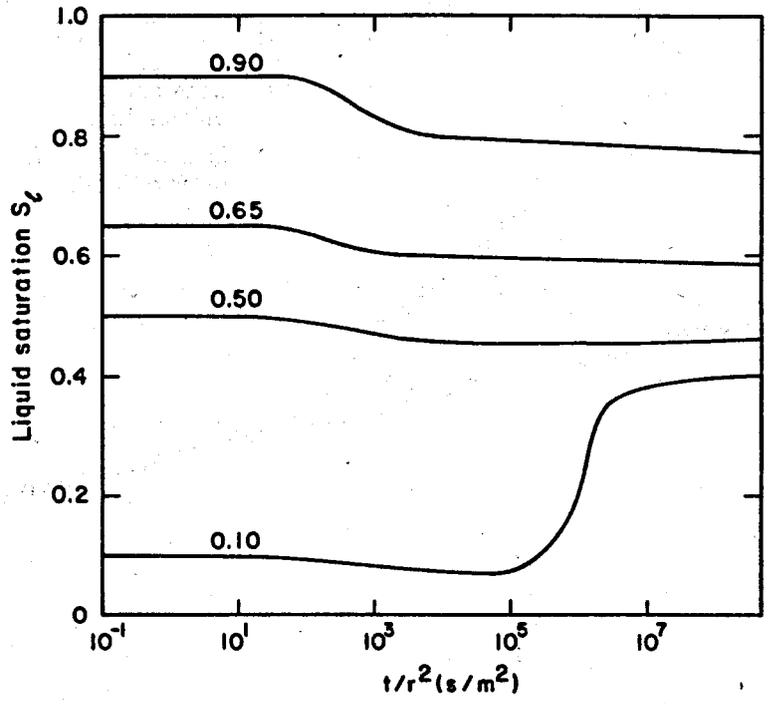


Figure 1. Liquid saturation response for constant mass production from the reservoir. Curves are labelled with initial liquid saturations (ref. 15). (XBL 804-7018)

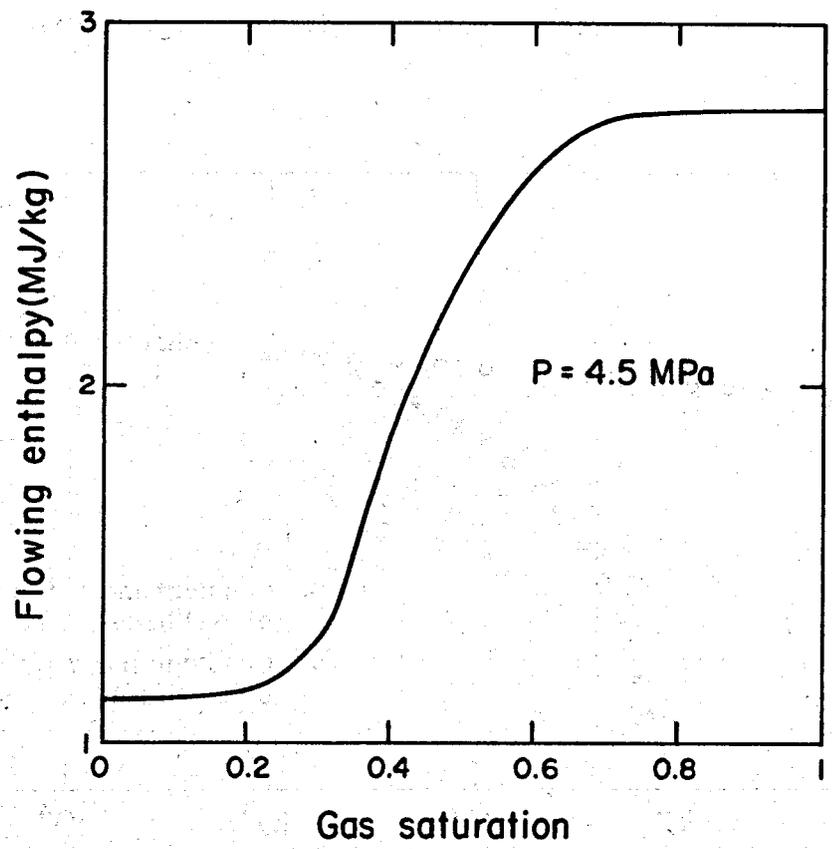


Figure 2. Flowing enthalpy versus vapor saturation for Corey-type relative permeability curves with $S_{fr} = 0.3$ and $S_{vr} = 0.05$. (XBL 811-2126)

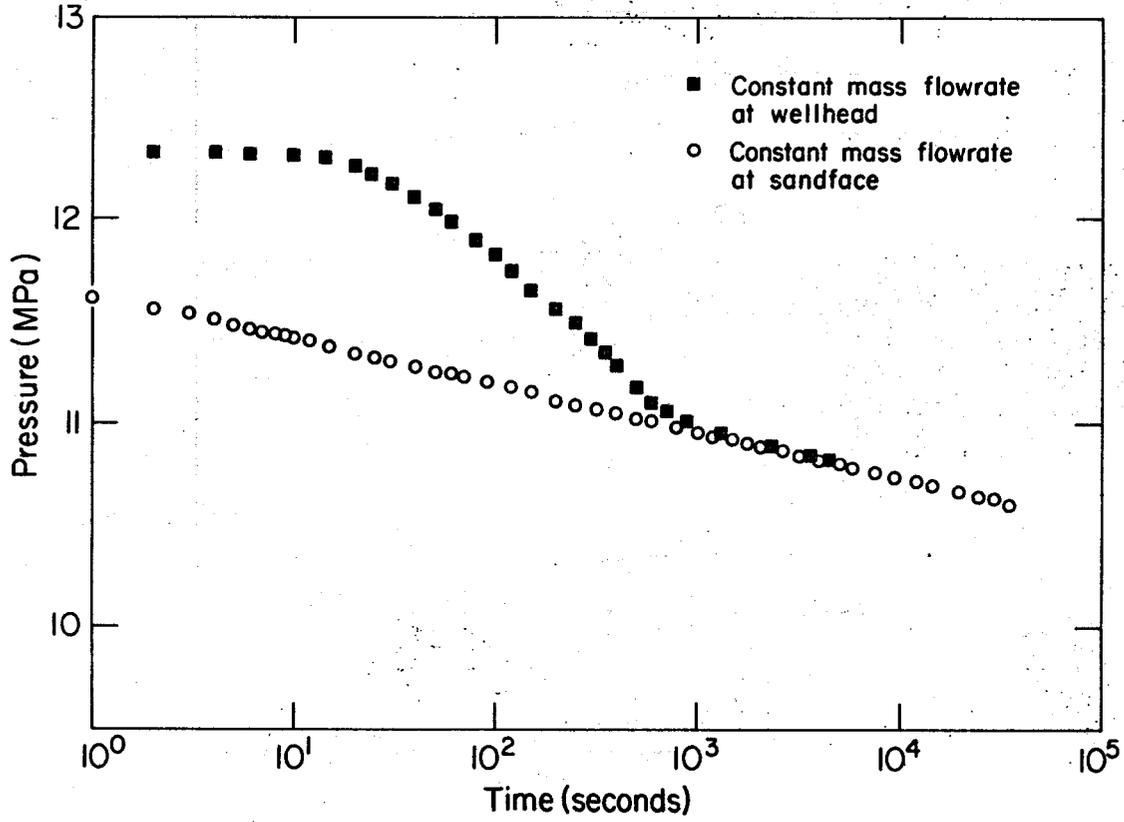


Figure 3. Pressure drawdown curve for example 1. (XBL 811-2123)

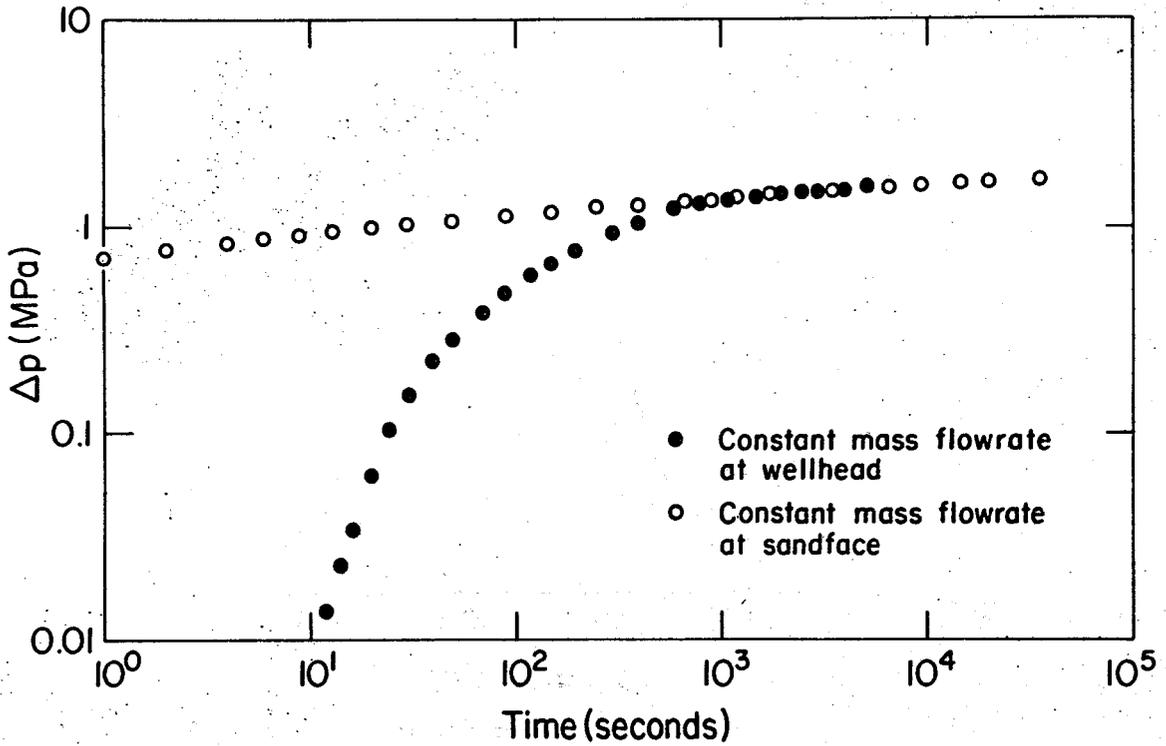


Figure 4. Log-log plot of pressure drawdown curve for example 1. (XBL 811-2122)

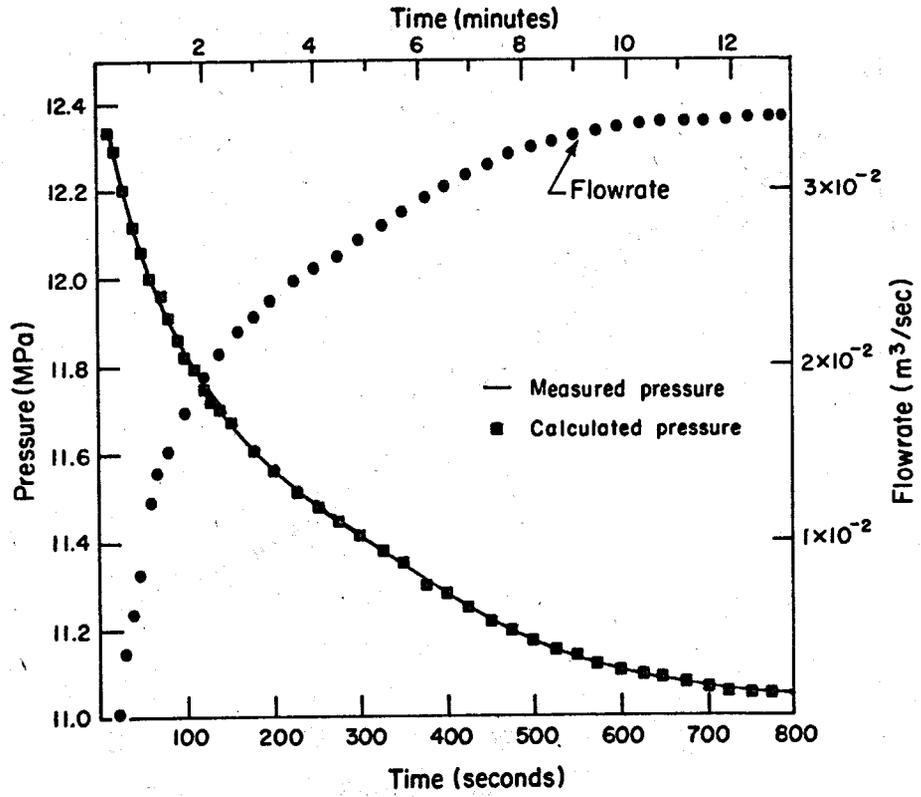


Figure 5. Sandface flowrate and drawdown pressure for example 1. Calculated pressure match using ANALYZE is also plotted. (XBL 811-2124)

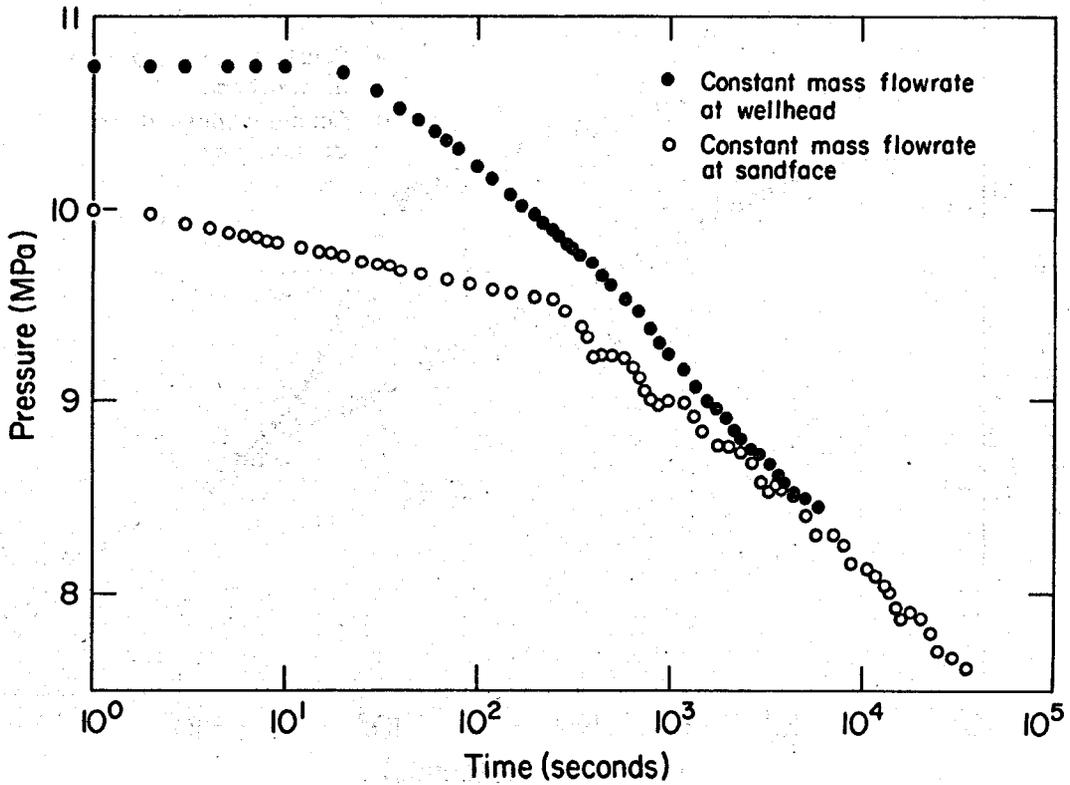


Figure 6. Pressure drawdown curve for example 2. (XBL 811-2118)

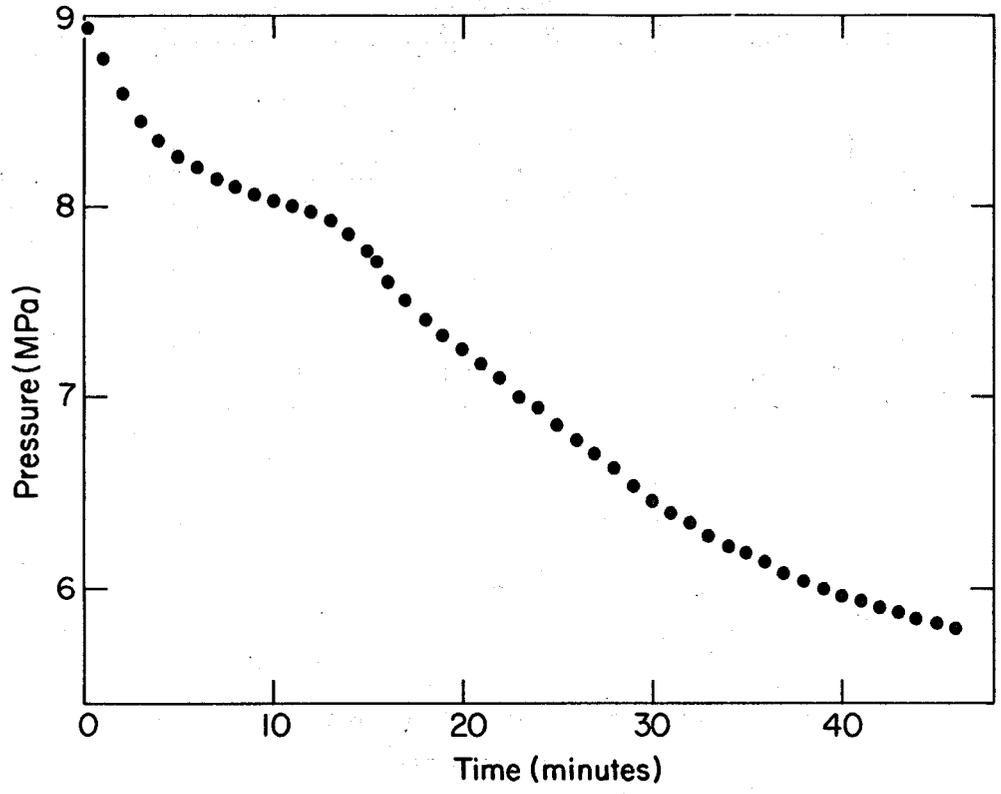


Figure 7. Linear plot of pressure drawdown curve for example 3. (XBL 811-2117)

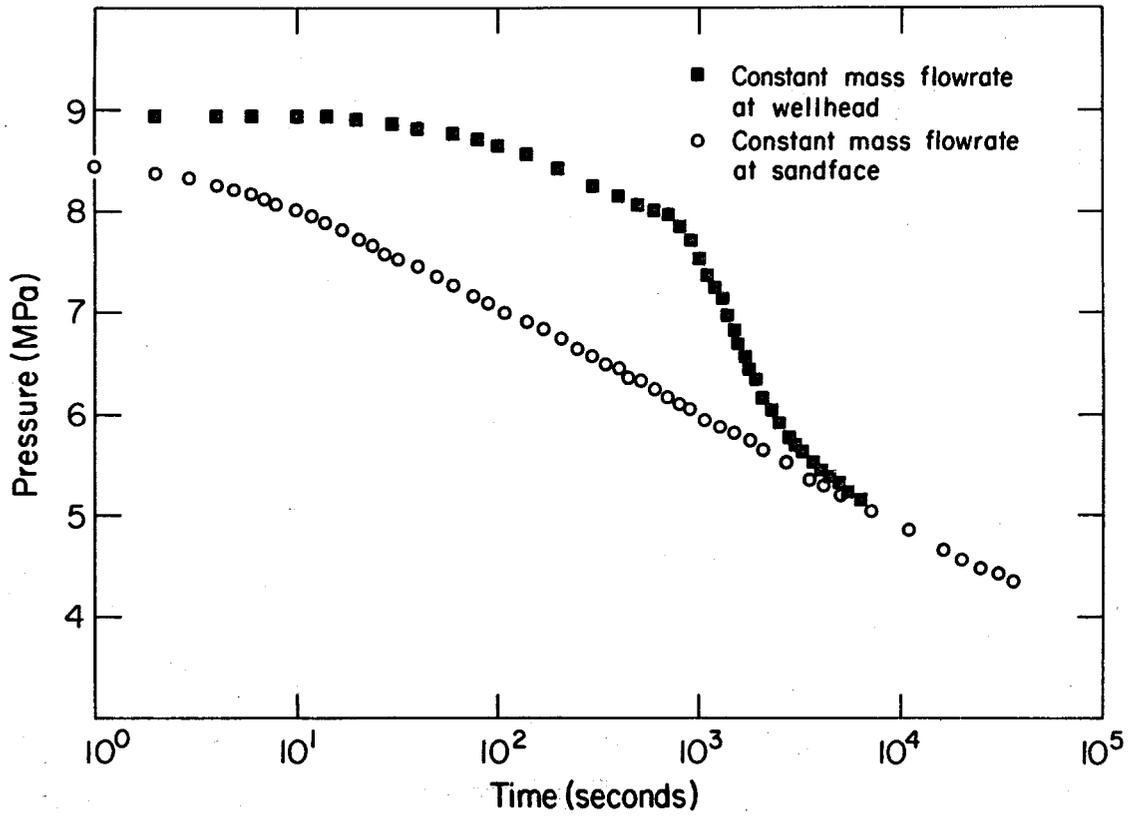


Figure 8. Semi-log plot of pressure drawdown curve for example 3. (XBL 811-2116)

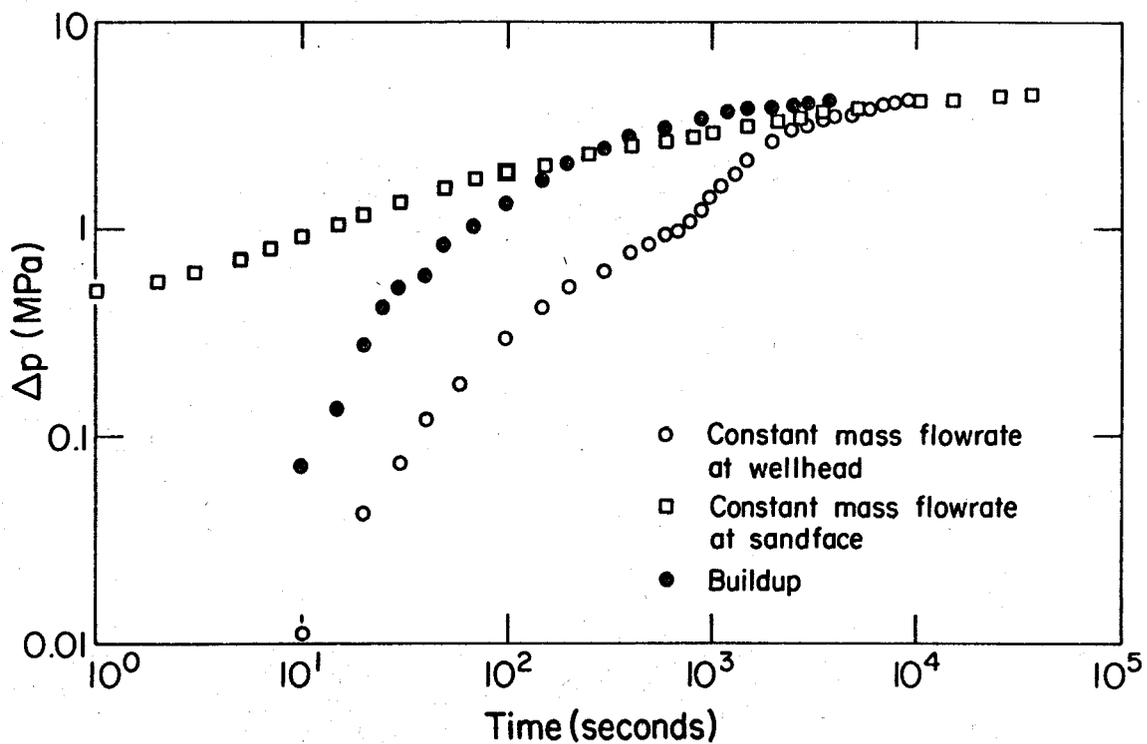


Figure 9. Log-log plot of pressure drawdown and pressure buildup for example 3. (XBL 811-2125)

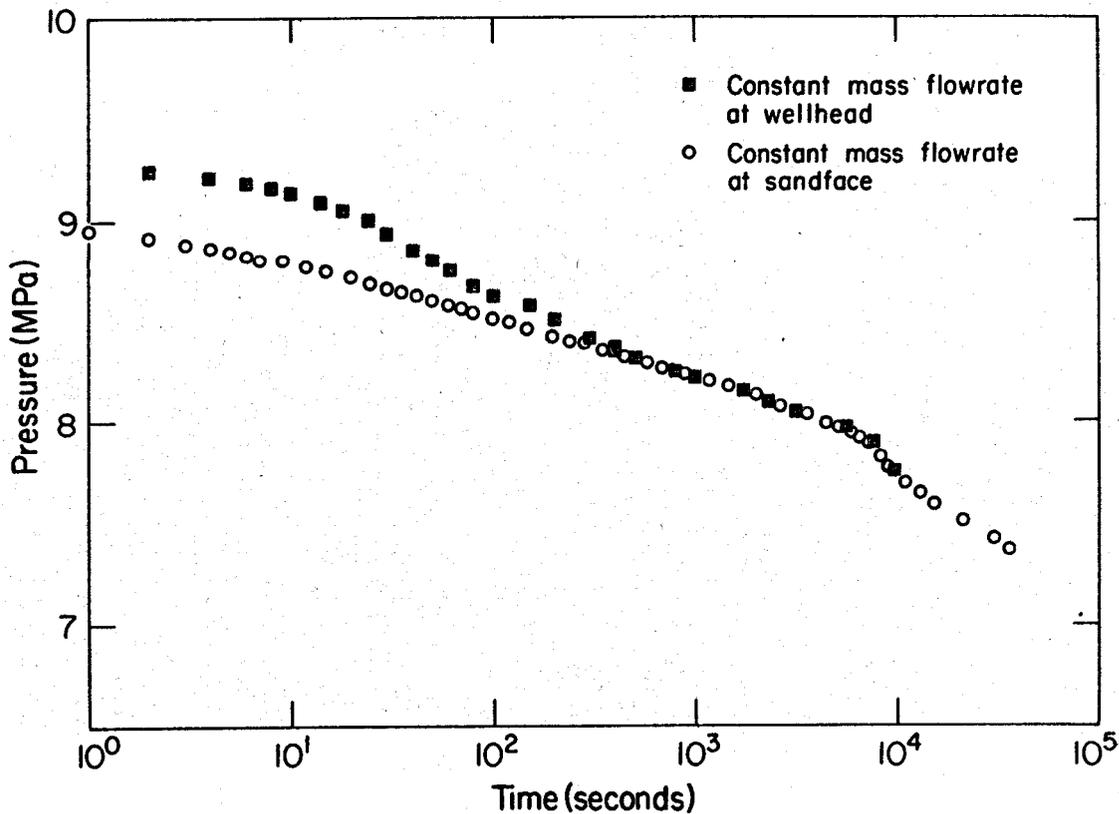


Figure 10. Pressure drawdown for example 4. (XBL 811-2120)