PRESSURE INTERFERENCE DATA ANALYSIS FOR TWO-PHASE GEOTHERMAL RESERVOIRS

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Introduction

Pressure interference tests are extremely valuable for establishing reservoir connectivity and for determining interwell transmissivity, but planning, executing and interpreting pressure interference tests in two-phase geothermal systems poses special difficulties. Since the effective "pressure diffusivity" for a two-phase system is much smaller than for a single phase system, it will take a long time to propagate pressure signals through a reservoir which is two-phase throughout. Consequently, a pressure interference test in a system which is initially two-phase may well be impractical. A more tractable situation occurs when a single-phase reservoir evolves into a two-phase system as a result of fluid production during the test. In this case, a boiling front propagates outward (during drawdown) from the producing wellbore(s); for practical purposes, the boiling front may be treated as a constant pressure boundary. If the initial reservoir pressure is high enough, and if the two-phase region created during the drawdown phase is not too extensive, the entire reservoir will return to single-phase conditions sometime after the cessation of fluid production (see Garg and Pritchett, 1984). In this paper, we consider a single phase reservoir which evolves into a two-phase system as a result of fluid production. Our goal is to examine the character of the pressure signal to be expected at the observation well, and to develop practical methods for the analysis of this pressure signal to yield reservoir transmissivity and compressibility despite the two-phase effects.

Mathematical Model

Garg (1980) considered the pressure response of a single-phase reservoir which becomes a two-phase system due to production. In this case, the reservoir is two-phase for $r < R$ [$R = R(t)$ denotes the location of the boiling front] and is single phase for $r > R$. Consider a fully penetrating well located in an infinite reservoir of thickness h. Assuming that the skin factor is zero, the pressure response for flow at a constant mass rate of production is given by (Garg, 1980):

$$0 < r < R:\ p = p_s + \frac{M\ \nu_t}{4\pi\ k\ h} \left\{ \mathrm{Ei} \left[\frac{-r^2}{4t\ D_t} \right] - \mathrm{Ei} \left[-\lambda^2 \right] \right\} \tag{1}$$

and

$$r > R:\ p = p_i + \frac{p_s - p_i}{\mathrm{Ei} \left\{ -\lambda^2\ D_t/D_\ell \right\}} \times \mathrm{Ei} \left[\frac{-r^2}{4t\ D_\ell} \right] \tag{2}$$

where

$$R = 2\lambda \left[D_t\ t \right]^{1/2} \tag{3}$$

and λ is the root of

$$\frac{p_s - p_i}{\mathrm{Ei} \left[-\lambda^2\ D_t/D_\ell \right]} = \frac{M\ \nu_\ell}{4\pi\ k\ h} \exp \left[-\lambda^2\ (1 - D_t/D_\ell) \right] \tag{4}$$

In Equations (1) to (4), D_ℓ is the diffusivity for the liquid region, D_t is the diffusivity for the two-phase region, h is the formation thickness, k is the absolute permeability, $k_{r\ell}(k_{rg})$ is the liquid (gas) relative permeability, M is the rate of mass production, p is the pressure, p_i is the initial formation pressure, p_s is the saturation pressure, r is radius, t is time, $\nu_\ell(\nu_g)$ is the liquid (gas) kinematic viscosity, and ν_t [$= (k_{r\ell}/\nu_\ell + k_{rg}/\nu_g)^{-1}$] is the two-phase kinematic viscosity.

The liquid-region diffusivity D_ℓ is given by:

$$D_\ell = \frac{k}{\phi\ \rho_\ell\ \nu_\ell\ C} \tag{5}$$

where ϕ is the porosity, ρ is the liquid density, C ($= C_m/\phi + C_\ell$) is the total formation compressibility, C_m is the uniaxial formation compressibility, and C_ℓ is the liquid compressibility. The effective pressure diffusivity for the two-phase reservoir region can be written as:

$$D_t = \frac{k}{\phi\ \rho_t\ \nu_t\ C_t}\ , \tag{6}$$

where ρ_t and C_t denote the density of the flowing mixture and the total compressibility of the two-phase region respectively. Given the flowing enthalpy H_t, the density of the flowing mixture ρ_t can be evaluated from:

$$\frac{1}{\rho_t} = \frac{H_g - H_t}{L\ \rho_\ell} + \frac{H_t - H_\ell}{L\ \rho_g} \tag{7}$$

where H_g (H_ℓ) is the steam (liquid) enthalpy corresponding to the measured bottomhole pressure, and L is the heat of vaporization. For practical purposes, the total two-phase compressibility C_t is given sufficiently accurately by the following approximate expression (Grant and Sorey, 1979)

$$\phi\ C_t = \langle\rho c\rangle \left[\frac{(\rho_\ell - \rho_g)}{L\ \rho_\ell\ \rho_g}\right]^2 (T + 273.15) \tag{8}$$

$$\langle\rho c\rangle = (1 - \phi)\ \rho_r\ c_r + \phi\ [\rho_\ell\ c_\ell\ S_\ell + \rho_g\ c_g\ (1-S_\ell)] \tag{9}$$

where ρ_r is the rock grain density, c_g, c_ℓ, and c_r denote the specific heat for gas, liquid, and rock, S_ℓ is the liquid saturation, and T is the reservoir temperature.

The *in situ* liquid saturation S_ℓ cannot be directly measured; in this work, we will therefore employ an approximate expression for $\langle\rho c\rangle$ obtained by setting $S_\ell = 1$ in Equation (9). It is straightforward to show that this approximation will lead to an underestimate for formation transmissivity kh/ν_ℓ.

For $4t\ D_t/r_w^2 > 100$ (here r_w denotes the well radius), Equation (1) can be approximated to give the following expression for bottomhole pressure, $p_w(t)$:

$$p_w(t) = p_s - \frac{M\ \nu_t}{4\pi\ k\ h}\ Ei(-\lambda^2) - \frac{1.15\ M\ \nu_t}{2\pi\ k\ h}\left\{\log_{10}\frac{D_t\ t}{r_w^2} + 0.351\right\} \tag{10}$$

Equation (10) implies that a plot of p_w versus $\log_{10} t$ should be a straight line and that the two-phase kinematic mobility k/ν_t is given by:

$$k/\nu_t = \frac{1.15\ M}{2\pi\ h\ m} \tag{11}$$

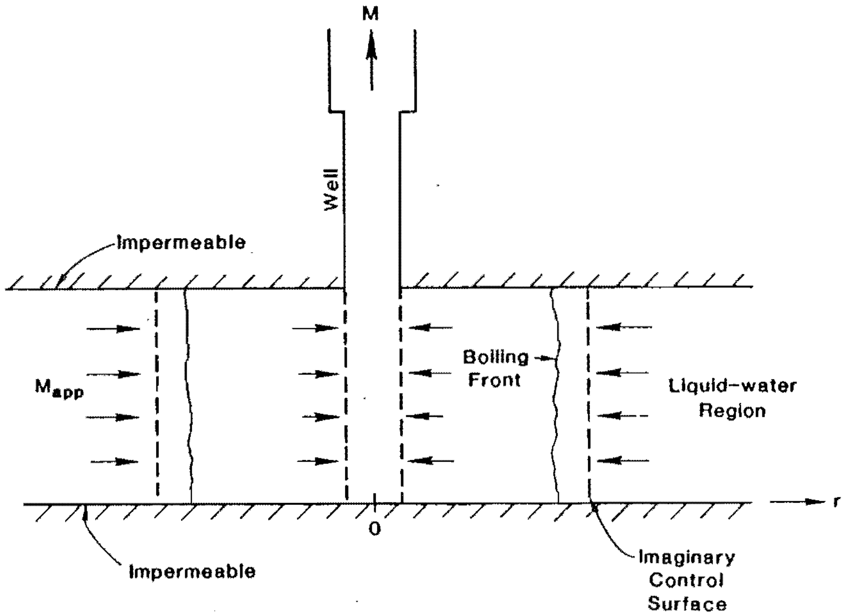
where m denotes the slope of the straight line.

In deriving this solution, Garg (1980) assumed that the two-phase region can be characterized by a constant kinematic mobility k/ν_t and a constant diffusivity D_t. In reality, the situation is much more complex. Both the kinematic mobility and diffusivity vary throughout the two-phase region. Since D_t is variable in the two-phase region, Equation (2) gives only an approximate solution for the pressure response in the single-phase region of the reservoir. It should also be noted that Garg's solution is only valid for the drawdown phase. Because of nonlinear effects in two-phase flow, superposition cannot be used to compute the buildup response. Despite these limitations, Garg's solution serves as a convenient point of departure for analyzing the observed pressure interference signal. In the following, it will be assumed that the reservoir fluid remains single-phase liquid in the vicinity of the observation well, and that *in situ* boiling is limited to a region surrounding the production well. Equation (2) is equivalent to the line source solution for a well producing a single-phase liquid at a constant rate of mass production M_{app}:

$$M_{app} = \frac{p_s - p_i}{Ei\left[-\lambda^2\ D_t/D_\ell\right]} \cdot \frac{4\pi\ k\ h}{\nu_\ell} = M\ \exp\left[-\lambda^2\ (1-D_t/D_\ell)\right]. \tag{12}$$

The apparent mass flow rate M_{app} is always less than the actual flow rate M.

The accompanying figure illustrates the situation in a schematic fashion around the production well prior to shutin. Consider an imaginary control surface surrounding the two-phase zone. The volume enclosed by this surface is taken to be as small as possible, but large enough to encompass the entire two-phase region at its maximum extent. In the absence of the two-phase region, the total inward mass flow crossing the imaginary control surface (M_{app}) will be equal to the total discharge rate (M), apart from a very small discrepancy due to effects of finite water compressibility. If a two-phase zone is present, the mass flux across the imaginary control surface (M_{app}) will be less than the well discharge rate (M); the difference amounts to the rate at which steam volume is being created in the two-phase region multiplied by the difference in density between liquid water and steam. In other words, only part of the fluid produced from the well (M_{app}) is obtained from the outer single-phase liquid region; the remainder ($M - M_{app}$) is withdrawn from storage within the expanding two-phase region.



Development of two-phase zone around production well.

At the moment of shutin, a two-phase region is present surrounding the well. If sufficient shutin time is allowed, pressures everywhere in the reservoir will eventually return to their predischarge values. Because the temperature within the two-phase region will actually be lower than the initial reservoir temperature, it follows that eventually, the two-phase region must condense away and the entire reservoir must revert to the original single-phase state. Since at the moment of shutin, the total mass of fluid within the imaginary control surface is less than it will be after the steam has condensed, it is evident that fluid must continue to flow inward through the imaginary control surface even after the well itself has been shut in. This afterflow will usually be relatively slow but may persist for a long period of time, until the entire steam zone has condensed away. Only then will flow across the control surface finally cease.

The preceding discussion suggests that the observed pressure interference signal may be analyzed in a straightforward manner provided a method is available for estimating the apparent mass flow rate M_{app}. Unfortunately, the calculation of M_{app} requires a knowledge of single-phase and two-phase diffusivities and the formation permeability. Since the latter quantities are the unknown parameters, it is not feasible to estimate M_{app} prior to solving Equations (1) through (11) for D_{ℓ}, D_t and k.

A perusal of Garg's solution suggests the following procedure for analyzing the pressure interference data:

1. Match the observed pressure interference signal to the line source type curve (see e.g. Earlougher (1977) for a discussion of the matching procedure). The matching procedure essentially involves (1) plotting observed pressure change Δp ($= p_i - p$) versus time t on a log-log scale and (2) overlaying the latter plot on the line source type curve. The type curve is a log-log plot of nondimensional pressure p_D versus a nondimensional similarity variable r_D^2/t_D,

$$p_D = -0.5 \text{ Ei } [-r_D^2/4\ t_D]. \tag{13}$$