NUMERICAL SIMULATION OF WELL CHARACTERISTICS COUPLED WITH STEADY RADIAL FLOW IN A GEOTHERMAL RESERVOIR

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## INTRODUCTION

Output curves of flowrate versus wellhead pressure, referring to well characteristics, provide information on well productivity. The well characteristics are affected by reservoir parameters such as reservoir pressure, fluid temperature, and permeability-thickness product(kh). Geothermal wells drilled in a water-dominated reservoir discharge a steam-water mixture. Therefore, a two-phase flow wellbore simulator is a useful tool to evaluate the effects of these parameters on the well characteristics. Flowing conditions of fluid at a feed zone can be a single- or a two-phase. This difference is attributed to a degree of pressure decrease in the reservoir. Thus, a fluid flow in the reservoir should be included into a wellbore model in order to obtain conditions at the feed zone for simulation. We have carried out numerical simulations of well characteristics using the wellbore model when the fluid starts flashing in the well as well as in the reservoir.

## MODEL

Figure 1 shows a schematic of wellbore model coupled with a single- and a two-phase flow in a reservoir. In developing a numerical model, following assumptions are made: 1)the reservoir is horizontal and radial symmetric, 2)the fluid flow in the reservoir is under steady state and isoenthalpy, 3)the gravity acceleration is neglected in the reservoir, 4)the fluid flows into the well from a single feed zone, 5)the well is vertical with uniform diameter, 6)the fluid flow in the well is under steady state and isoenthalpy.

In combination with continuity and momentum equations of fluid, a two-phase flow in the wellbore is expressed in an integrated form:

$$\frac{1}{j}\int_{P_{wb}}^{P_{wh}} \frac{dP}{jv+\dfrac{g}{jv}} + \frac{D}{\lambda}\ln\frac{j^2v_{wh}^2+g}{j^2v_{wb}^2+g} + Ht = 0 \qquad (1)$$

$$j = \frac{G}{F}\sqrt{\frac{\lambda}{2D}}$$

where P(Pa) is the pressure, v($m^3$/kg)the average specific volume of two-phase mixture, Ht(m)the well length of two-phase flow, g($m/s^2$)the gravity acceleration, G(kg/s)the total flow rate, F($m^2$)the cross-sectional area of well. Subscripts wb and wh indicate the representative point of the feed zone(or wellbottom) and the wellhead, respectively. The specific volume is expressed using void fraction, $\alpha$:

$$v = 1/(\alpha\rho_s + (1-\alpha)\rho_w) \qquad (2)$$

$\rho_s$ and $\rho_w$ are the densities of steam and water, respectively. Smith's formula is used for calculating the void fraction(Smith, 1969-1970).

When a single-phase fluid flows into the well, the fluid flows upward some distances and starts flashing at a place where the pressure decreased to the saturation pressure. A change in the specific volume of water in the single-phase flow is negligible small. Thus, the flow along a lower part of the well is expressed:

$$\frac{v_{wb}}{j^2v_{wb}^2+g}(P_s - P_{wb}) + H_s = 0 \qquad (3)$$

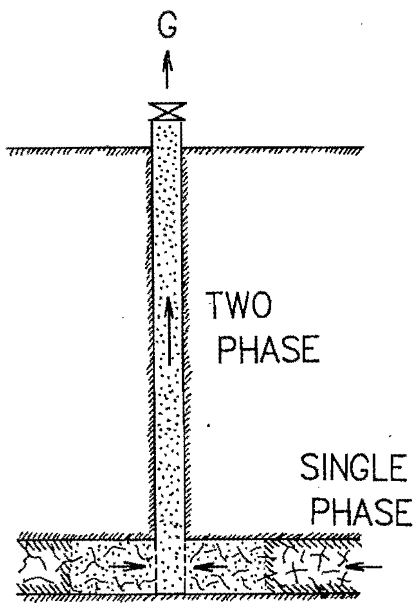


Fig.1 Schematic of a well model.

where $P_s$(Pa)is the saturation pressure of the fluid, and $H_s$(m) the well length of single-phase flow part. Friction factor, $\lambda$, for a commercial pipe is calculated from Karman's formula and is kept constant. For the two-phase flow part, a value of 1.1 times large as that for the single-phase flow is used.

A continuity equation in the reservoir is expressed:

$$-\frac{1}{r}\frac{\partial}{\partial r}(ru) = 0 \qquad (4)$$

$$u = -\frac{k}{\nu_t}\frac{\partial P}{\partial r} \qquad (5)$$

where $r$(m) is the radial distance, $u$(kg/(m$^2$s))the mass flux, $k$(m$^2$)the permeability, and $\nu_t$(m$^2$ /s)the total kinematic viscosity of two-phase fluid. The total kinematic viscosity is expressed(Grant et al, 1982):

$$\frac{1}{\nu_t} = \frac{k_{rw}}{\nu_w} + \frac{k_{rs}}{\nu_s} \qquad (6)$$

where $k_{rw}$ and $k_{rs}$ are the relative permeabilities for water and steam,respectively, $\nu_w$ and $\nu_s$ (m$^2$ /s)the kinematic viscosities of water and steam, respectively. X curves having $k_{rw}+k_{rs}=1$ is used for the relative permeabilities.

Introducing a normalized distance $R=\ln(r/r_w)$, the boundary conditions are:

$R=R_{wb}(=0)$ $\quad G=Au$
$R=R_s$ $\quad P=P_s$
$R=R_e$ $\quad P=P_e$

where $r_w$(m) and $R_{wb}$(-) are the well radius, $A$(m$^2$)the surface area of well at the feed zone, $R_s$(-) and $R_e$(-)the normalized distances of flash point and outer boundary radius, respectively, and $P_e$(Pa)the pressure at $R_e$. Integrating Eq.(5) from $R=R_{wb}$ to $R_s$ gives:

$$\frac{\partial P}{\partial R} = \frac{\int_{P_{wb}}^{P_s} \frac{\partial P}{\nu_t} \cdot \nu_t}{R_s} \qquad (7)$$

Further integration of Eq.(7) from $P_{wb}$ to arbitrary pressure P gives:

$$R = (R_s - R_{wb})\frac{\int_{P_{wb}}^{P_s} \frac{\partial P}{\nu_t}}{\int_{P_{wb}}^{P} \frac{\partial P}{\nu_t}} \qquad (8)$$

where R is the normalized distance for the pressure P. Equation(8) can be used to calculate pressure distribution in the two-phase flow region.

A flow rate of two-phase mixture at the feed zone is expressed:

$$G = uA\Big|_{R_{wb}} = 2\pi h \left(\frac{k}{\nu_t}\frac{\partial P}{\partial r}\right)\Big|_{R_{wb}} \qquad (9)$$

Substituting Eq.(7) into Eq.(9) yields:

$$G = 2\pi kh \frac{\int_{P_{wb}}^{P_s} \frac{\partial P}{\nu_t}}{R_s} \qquad (10)$$

The normalized radial distance, $R_s$, at which the fluid starts flashing is given by

$$R_s = R_e - \frac{2\pi kh}{G\nu_w}(P_e - P_s) \qquad (11)$$

When the single phase fluid flows into the well, the flowrate is expressed in a simple form:

$$G = \frac{2\pi kh(P_e - P_{wb})}{\nu_w R_e} \qquad (12)$$

Providing reservoir parameters and a discharge flow rate, the fluid pressure at the feed zone can be numerically calculated from equations above both for the single- and the two-phase flow in the reservoir. Then, a wellhead pressure can be calculated using Eq.(1) with/without Eq.(3) for the conditions at the feed zone.

Numerical simulations were carried out under conditions; the well depth is 1000 m, the diameter of well 0.2 m, the reservoir pressure($P_e$) 81.3 bar, the outer boundary radius 50 m.

## RESULTS AND DISCUSSION

Figure 2 shows a well characteristics for different permeabilities when the reservoir fluid temperature is 282.5 °C. The broken line represents a two-phase condition at the feed zone and the solid line a single-phase condition. The curve for 1 darcy-m indicates that the fluid always starts flashing in the reservoir over a wide range of wellhead pressure. Curves for larger permeabilities represent that a flashing point moves into the reservoir with an decrease in wellhead pressure, in other words, with an increase in the total flowrate. Large flowrates cause a pressure drop to a great extent in the reservoir. As a result, the fluid pressure decreases below the saturation pressure while flowing toward the well. The flowrate for 1 darcy-m shows a small increase with an decrease in the wellhead pressure. However, the flowrates for larger values in kh show an rapid increase with a decrease in the wellhead pressure.

Figure 3 shows a relationship between the total flowrate and the pressure at the feed zone for different permeabilities. The broken and solid lines represent the phase conditions at the feed zone as in Fig.2. When a single-phase fluid enters the well, a linear correlation is observed between the flowrate and the pressure for curves of 3 and 5 darcy-m. As the condition changed into the two-phase, the curves decrease in a non-linear manner with an increase in the

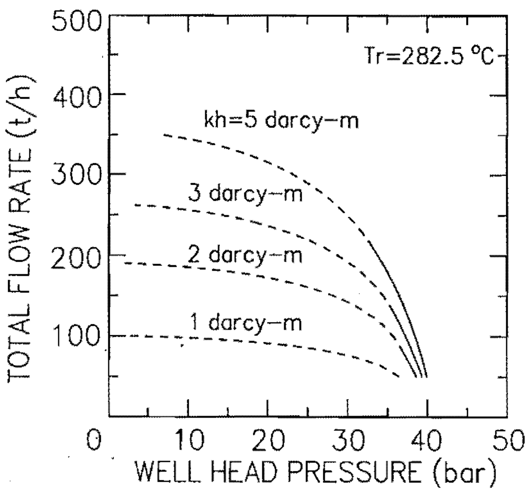


Fig.2 Well characteristics for different kh.

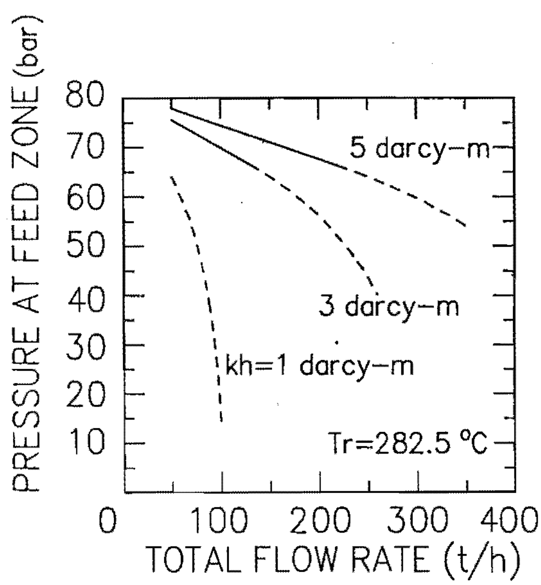


Fig.3 Relationship between total flow rate and pressure at feed zone for different kh.

flowrate. This is because that the integrated value of total kinematic viscosity in Eq.(10) increases as the two-phase flow region expands in the reservoir.

The effects of fluid temperatures on the well characteristics are illustrated in Fig.4. A kh value of 3 darcy-m is used. Two-phase conditions at the feed zone appears in three curves of 282.5, 270, and 260 °C. The flowrate at which a fluid phase changes at the feed zone becomes large for lower fluid temperatures. In a lower wellhead pressure range when the fluid flows into the well under the two-phase condition, an increase rate of flowrate becomes small with a decrease in the wellhead pressure. For example, the flowrate of 282.5 °C is the lowest among four curves in a wellhead pressure range below about 10 bar.


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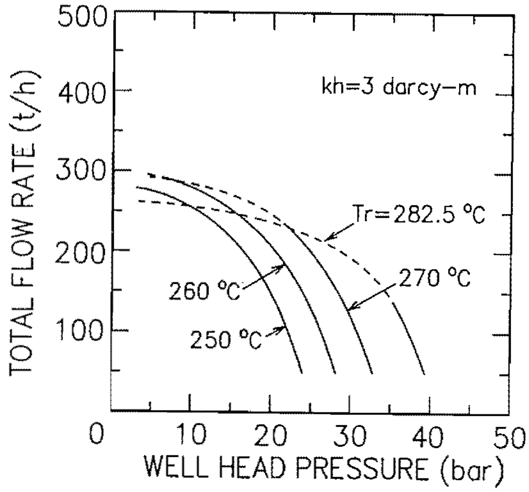


Fig.4 Well characteristics for different fluid temperatures.