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A WELLBORE FLOW MODEL IN THE PRESENCE OF CO_2 GAS

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ABSTRACT

The fluid produced by the geothermal wells in the Nigorikawa field which is located in southern Hokkaido, Japan's northern island, is rich in carbon dioxide(CO_2). The dissolved CO_2 causes a scale deposition problem of calcium carbonate($CaCO_3$).

Japan Metals & Chemicals Co., Ltd.(JMC) has already solved the $CaCO_3$ scale deposition problem by injecting a scale inhibiting chemical fluid directly and continuously through a injection tube extending into the production well.

The $CaCO_3$ scale deposition occurs at the flash point. It is important, therefore, to estimate the flash depth correctly so that the depth of the chemical injection point can be determined.

However, the boiling point curve of the geothermal fluid with dissolved CO_2 is different from that of pure water(H_2O). So, a wellbore flow model in the presence of CO_2 gas has been developed.

This model was tested by comparing the temperature and pressure values calculated by the computer to depth profiles drawn the Nigorikawa field data. As a result of the comparison, a satisfactory fitting has been obtained. A brief explanation of this model and a few examples of analysis by this model are presented.

INTRODUCTION

Japan Metals & Chemicals Co., Ltd.(JMC) has been producing steam and supplying it to three geothermal power stations in Japan. The locations of these power stations are shown in Fig. 1.

The Nigorikawa (Mori) geothermal field located in southern Hokkaido is a hot water dominated area. The Mori geothermal power station began to generate electricity (50MWe) in 1982. The fluid produced in the Nigorikawa field is rich in carbon dioxide(CO_2). The average concentration in 1982 was about 8 weight %. The present average concentration is about 1 weight %.

Output of the 50MWe power station decreased soon after the plant began operating in November, 1982. This is due to the plugging effect by the deposition of $CaCO_3$ scale formed in the production wells.

The problem of $CaCO_3$ scale deposition has been solved by injecting a scale inhibiting chemical fluid directly and continuously through a chemical injection tube extending into the production well. $CaCO_3$ scale deposition occurs at the flash point in each production well. Therefore,

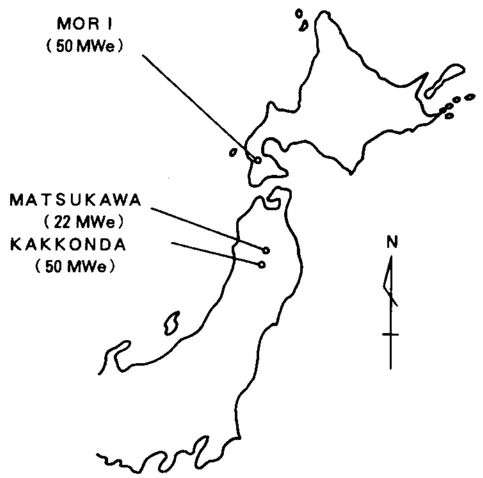

Fig.1 Locations of geothermal power stations where JMC supplies steam

to adopt this prevention system, it is necessary to estimate the flash depth of each production well so that a depth of the chemical injection point can be determined.

The wellbore flow model in the presence of CO_2 gas developed by JMC is useful for the following items.

- Calculation of the flash depth
- Estimation of the various reservoir conditions (kh, reservoir temperature and/or pressure)
- Prediction of the steam productivity from a production well making use of the predictions of the reservoir behavior made with a reservoir simulator.

GOVERNING EQUATIONS

A wellbore flow model in the presence of CO_2 gas has been developed under the following assumptions.

1. The geothermal fluid has steady-state flow.
2. The flash point is in the wellbore.
3. The CO_2 concentration in the incoming compressed water to the production well is constant even if the flow rate varies.
4. The heat exchanged between the geothermal fluid and surrouding rocks can be ignored.
5. Henry's law is valid.

This model is constructed from three calculation parts as shown Fig. 2.

(a) Calculation of bottom hole conditions

The single phase water flow in the formation in the vicinity of the production well can be expressed as Darcy's law.

$$G=2\pi kh\gamma/\mu/\ln(re/rw)\cdot(Pe-Pw) \qquad (1)$$

In this equation, viscosity and specific weight

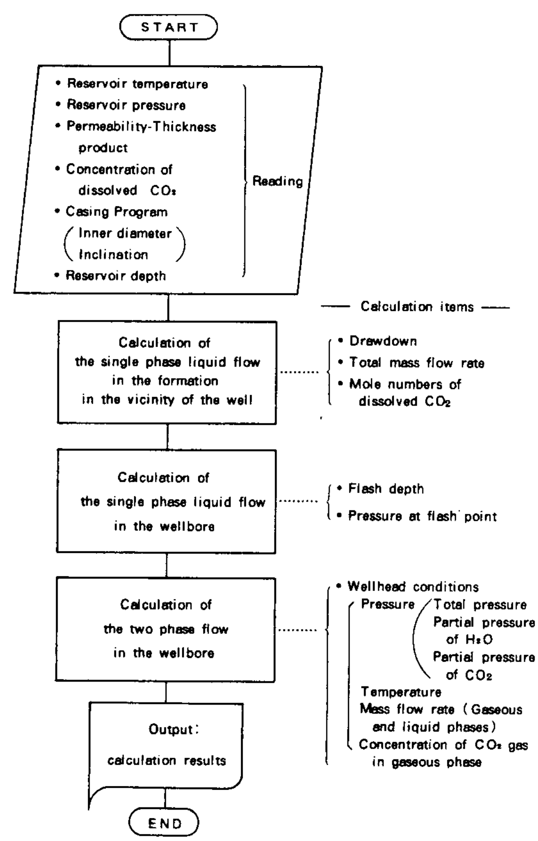

Fig. 2 Computer code flow diagram

values are assumed equal to those of pure water. Mole numbers of CO_2 in the incoming compressed water to the production well, furthermore, are calculated from

$$M_{CO_2}=1000G\cdot C_{CO_2}/44 \quad (2)$$

(b) Calculation of flash point

The flash point can be calculated from total pressure as the sum of partial pressure of CO_2 and vapor pressure of pure water at reservoir temperature. The partial pressure of CO_2 can be evaluated by Henry's law. Henry's constant is used in a function of temperature proposed by S.D.Malinin(1963).

$$K_{CO_2}=39.66+67.7403\cdot T-0.17884\cdot T^2 \quad (3)$$

The flash depth corresponding to this total pressure can be calculated from the upward flow equations of the single phase water. Thus

$$P_h=\gamma\cdot dl\cdot \cos(\theta) \quad (4)$$

$$P_f=\lambda/2/g/D\cdot\omega^2\cdot\gamma\cdot dl \quad (5)$$

(c) Calculation of two phase flow through the wellbore

The two phase upward flow through the wellbore is accompanied by a decrease in pressure and temperature. For the numerical approach to calculate the conditions in two phase flow, therefore, the secant method is used. That is, total pressure corresponding to an arbitrary drop of fluid temperature is calculated first. Secondly, the depth corresponding to this total pressure is calculated.

(c-1) Calculation of total pressure

The steam quality in the H_2O component can be calculated from

$$\chi=(h-h')/r \quad (6)$$

Mole numbers of water and steam can be calculated from

$$H_2OL=(1000G-44M_{CO_2})\cdot(1-\chi)/18 \quad (7)$$

$$H_2OV=(1000G-44M_{CO_2})\cdot\chi/18 \quad (8)$$

The mole ratio between gaseous and dissolved CO_2 is expressed by W.F.Giggenbach(1980). Thus

$$B_{CO_2}=10^{(4.7593-0.01092\cdot T)} \quad (9)$$

Mole numbers of dissolved CO_2, furthermore, can be also calculated from the definition equation of the vapor-liquid gas distribution coefficient(B_{CO_2}) as follows.

$$CO_2L=M_{CO_2}\cdot H_2OL/(H_2OV\cdot B_{CO_2}+H_2OL) \quad (10)$$

Total pressure can be obtained as the sum of partial pressure of CO_2 calculated from (3) equation and vapor pressure of pure water corresponding to an arbitrary temperature.

(c-2) Calculation of a corresponding depth to the total pressure

The pressure drop per unit pass length can be expressed as the sum of head, acceleration and friction losses. A depth corresponding to the total pressure, therefore, is calculated from these losses.

•Head loss

The head loss can be evaluated from the definition equation of the void fraction. Thus

$$P_h=[fg/\upsilon_V+(1-fg)\cdot\upsilon_L]\cdot dl\cdot\cos(\theta) \quad (11)$$

where the specific weight of the gaseous phase is calculated from the state equation of an ideal gas as

$$\upsilon v=(H_2OV/P_{H_2O}+CO_2V/P_{CO_2})\cdot 0.8478\cdot(T+273.15)/(H_2OV\cdot 18+CO_2V\cdot 44) \quad (12)$$

The void fraction, furthermore, is evaluated by an experimental equation obtained from a matching with the field data from the Takinoue.

•Acceleration loss

The acceleration loss can be evaluated from the definition equation of momentum as

$$Pa=(G/F)^2/g\cdot(\upsilon me-\upsilon min) \quad (13)$$

where

$$\upsilon me=[1+\chi\cdot(S-1.0)]\cdot[1+\chi\cdot(\upsilon v/\upsilon L/S-1)]\cdot\upsilon L \quad (14)$$

$$\chi=(H_2OV\cdot 18+CO_2V\cdot 44)/G \quad (15)$$

•Friction loss

The friction loss is evaluated from the following equations depending upon the flow regimes.

[Bubble flow]

An equation proposed by Inoue and Aoki(1965) is adopted. Thus

$$Pf=(B/BL)\cdot[(1-fg)+fg\cdot\upsilon L/\upsilon v]^{3/4}/[1-fg/K\cdot(1-\upsilon L/\upsilon v)]^{7/4}\cdot\Delta PLO \quad (16)$$

[Slug flow]

An adopted equation is proposed by D.Chisholm et al.(1969-70).

$$Pf=\upsilon m/(1-\chi)^2/\upsilon L\cdot\Delta PLO \quad (17)$$

[Mist flow]

The pressure loss under the condition of mist flow is calculated from the following equation proposed by Akagawa(1974) as the sums of head, acceleration and friction losses. Thus

$$PT=Ph+Pa+Pf=(4\cdot\tau L/D+\gamma m)\cdot dl\cdot\cos(\theta) \quad (18)$$

[Discrimination of flow regime]

Two discriminating criteria proposed by P. Griffith et al.(1961) and L.P.Golan et al. (1969-70) are adopted to determine the flow pattern.

COMPARISON WITH FIELD DATA

The model described above was tested by comparing the values calculated by the computer with temperature and pressure profiles drawn from the Nigorikawa field data measured during production.

JMC measures temperature and pressure profiles during production with the Kuster gauge. The Kuster gauge's error gradually changes owing to the change of the coefficient of elasticity of its mechanical sensor (bimetal or bourdon tube). So, to maintain the accuracy, JMC calibrates the Kuster gauge with a calibration machine developed in house.

Fig. 3 shows the comparison between temperature and pressure profiles calculated by the computer and field profiles. As is evident from Fig. 3, the calculated values gives good agreement with the Nigorikawa field data. It seems, hence, that this model is accurate enough for practical use.

EXAMPLES OF USE

(a) Estimation of the reservoir conditions

The $CaCO_3$ scale deposition in the production wells in the Nigorikawa field has been prevented by a scale inhibiting chemical fluid injected directly and continuously through a chemical injection tube extending into the well to the geothermal fluid. A production logging in order to measure the historical changes of reservoir temperature and pressure of the production well cannot be carried out while the chemical injection tube is in place.

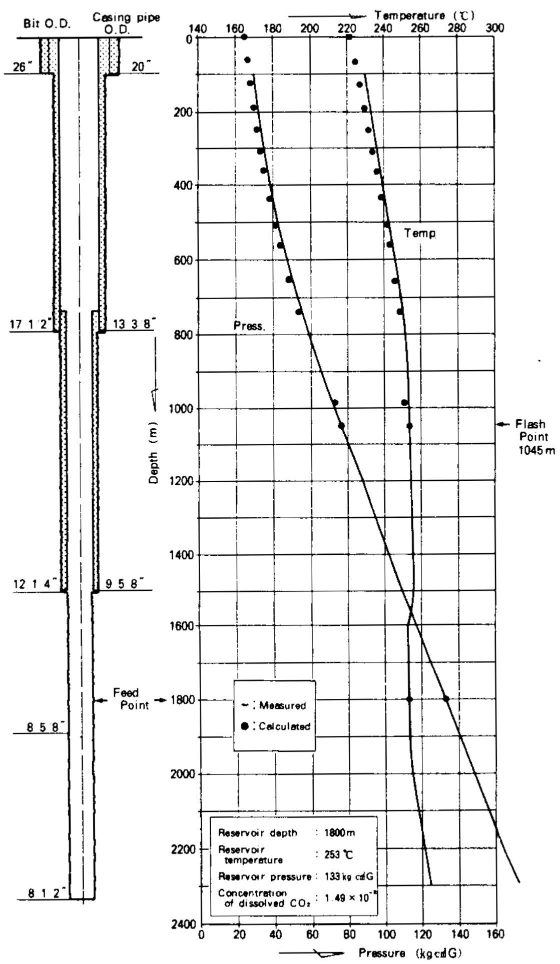

Fig. 3 Comparison between temperature and pressure profiles calculated by the computer and field profiles during production

So, we estimate the reservoir conditions through matching with a flow characteristic (flow rate versus wellhead pressure) obtained by the surface equipment only as shown Fig. 4.

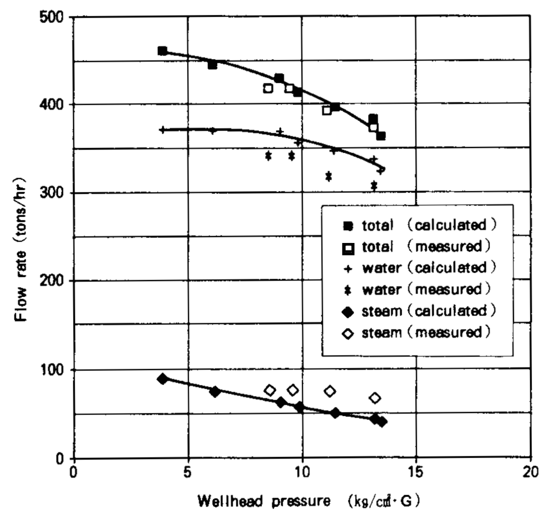

Fig.4 Matching result between measured and calculated characteristic production curves

(b) Determination of the depth of the chemical injection point

In order to prevent $CaCO_3$ scale deposition, the location of the chemical injection point in the production well must be lower than the flash depth. Hence, we evaluate the flash depth as shown in Fig. 5 and determine the chemical injection point.

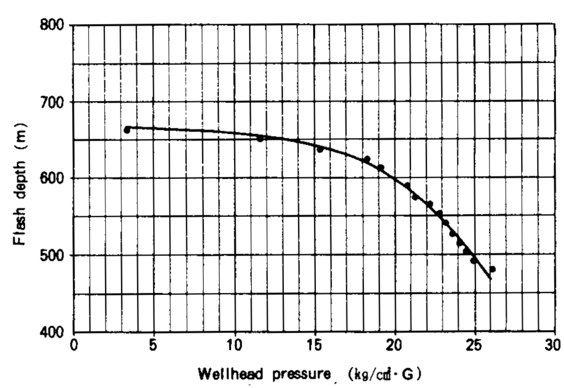

Fig.5 Correlation between flash depth and wellhead pressure

(c) Prediction

Presently, we are evaluating the Nigorikawa field through the historical matching by the reservoir simulator. In predicting the reservoir behavior, it will be important that the steam productivity from each production well at an arbitrary time is predicted accurately. So, this model will play an important part in obtaining an accurate prediction.

CONCLUSIONS

1. A wellbore flow model in the presence of CO_2 gas has been developed.
2. Comparison of the results of the computer program and the experimental temperature and pressure profiles shows that these are in satisfactory agreement.
3. The wellbore flow model can be applied to estimate the reservoir conditions in the vicinity of a production well through the matching between a measured characteristic production curve and a calculated one.
4. The model can be also used in evaluating the depth of $CaCO_3$ scale deposition. The $CaCO_3$ scale problem in the production wells can be, hence, prevented by a chemical injection tube inserted deeper than the calculated flash depth in the well, wherein scale inhibiting chemical fluid is injected through the tube directly and continuously to the geothermal fluid.
5. A good example of use will be in predicting the steam production rate from each well with the prediction results by reservoir simulator.

NOMENCLATURE

B =function of void fraction, specific weight, velocity, and viscosity
B_{CO_2}=vapor-liquid gas distribution coefficient
B_L =constant
C_{CO_2}=CO_2 concentration in the incoming compressed fluid to the well
CO_2L=mole numbers of dissolved CO_2 (mole)
CO_2V=mole numbers of gaseous CO_2 (mole)
D =inner pipe diameter (m)
dl =unit pass length (m)
F =cross-sectional area of pipe (m^2)
fg =void fraction
G =total mass flow rate (kgf/s)
g =gravity acceleration (m/s^2)
h =specific enthalpy of the incoming compressed fluid to the well (kcal/kgf)
h' =specific enthalpy of water (kcal/kgf)
H_2OL=mole numbers of water (mole)
H_2OV=mole numbers of steam (mole)
K =flow parameter
K_{CO_2}=Henry's constant
kh =permeability•thickness product (m^3)
M_{CO_2}=mole numbers of CO_2 in the incoming compressed fluid to the well (mole)
P_a =acceleration loss (kgf/m^2)
P_{CO_2}=partial pressure of CO_2 (kgf/m^2)
P_e =reservoir pressure (kgf/m^2)
P_f =friction loss (kgf/m^2)
P_{H2O}=vapor pressure of pure water (kgf/m^2)
P_h =head loss (kgf/m^2)
P_T =total pressure loss (kgf/m^2)
P_w =wellbottom flowing pressure (kgf/m^2)
r =heat of vaporization (kcal/kgf)
r_e =reservoir radius (m)
r_w =wellbore radius (m)
T =temperature (°C)
γ =specific weight of fluid (kgf/m^3)
γ_m =specific weight of the liquid-gas mixture (kgf/m^3)
θ =inclination (deg.)
λ =friction factor
μ =viscosity ($kgf \cdot s/m^2$)
τ_L =shearing stress on the pipe (kgf/m^2)
υ_L =specific volume of liquid phase (m^3/kgf)

υ_m =specific volume of the liquid-gas mixture (m^3/kgf)

υ_{me} =specific volume of the liquid-gas mixture at the outlet of interval (m^3/kgf)

υ_{min}=specific volume of the liquid-gas mixture at the inlet of interval (m^3/kgf)

υ_v =specific volume of gaseous phase (m^3/kgf)

χ =quality

ω =velocity (m/s)

ΔP_{LO}=friction loss under the single phase liquid flow (kgf/m^2)

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