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A TEMPERATURE DROP MODEL FOR TWO-PHASE FLOW IN GEOTHERMAL WELLBORES

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ABSTRACT

This temperature-drop model is formulated as an answer to the question, 'How much further up the wellbore will a unit mass of fluid be when its temperature is exactly one-degree cooler than at its current position?'. The repeated calculation yields a temperature profile extending upwardly from the bubble point. This approach is based on a paradigm that emphasizes temperature and volume for a system that is dominated by one component. It has only a small overlap with the more popular paradigm for this topic which involves mechanical pressures and energy balances.

A set of plots is given which shows the effects on temperature and pressure profiles due to changes of single factors when all other factors are held constant. The factors include common wellbore and reservoir parameters. These latter plots give considerable insight into wellbore processes and the nature of constraints on two-phase flow for an essentially one-component substance.

INTRODUCTION

Although the popular view of wellbore dynamics is a mechanical one which emphasizes pressures and energy balances, an alternative paradigm is available which emphasizes temperatures and volumes. Of course, there is some overlap between the two approaches because they are alternative views of the same phenomena. For example, both incorporate PVT relationships of gases. However, the contrasts are more profound.

To a chemist, the total pressure of a system containing vapors is the sum of all the partial pressures, which can be assembled in terms of temperature and composition, ignoring mechanical energies. It is such a chemist's view that provides the main vehicle for this temperature-drop model, to which is appended a few mechanical concepts.

This model takes advantage of the physical fact, Equation (1), that the pressure in a two-phase watery system is proportional to an exponential function of the reciprocal of the absolute temperature, wherein vapor volume plays no great role. This is fundamentally different from the PVT relationships of single-phase gases, yet is a highly accurate view of the water-dominated geothermal fluid.

$$\ln P/2.303 = 6.7028 - 0.00335N - 3712/(T+460) \quad (1)$$

The coefficients of (1) are based on Ref. (1), the units on P are psia, T is degrees Fahrenheit, and N is the weight percent NaCl which is equivalent to the mixed salt composition of a brine. Because (1) involves an equilibrium between liquid and vapor there is no term for volume.

Two other troublesome factors in wellbore flow modeling are greatly simplified through this approach. The effects of dissolved salts are essentially linear in the logP-T(abs) field, and the roles of dissolved gases can be accurately accounted for by simple addition.

The new vapor volume is essentially that of new steam due, approximately, to adiabatic boiling, and to expansion of steam formed earlier. The exact volume is less than what one would calculate for simple cumulative steam flash. Computing the effects of several non-idealities is one essence of the model. This gives form to the model which enables it to imitate real and hypothetical wellbore conditions in terms of familiar physical concepts.

CONSTRUCTION OF THE MODEL

The main mathematical task is to compute ZI, the longitudinal distance in an ideal wellbore between two points that are exactly one degree different in temperature. That involves finding the mass of fluid and its specific volume, VF, within the interval that has a cross-sectional area A, as in (2).

$$ZI = [(DP/G)][VF]/A \quad (2)$$

To a first approximation, the mass is proportional to the pressure difference, DP, between the two points divided by the gravitational constant G. DP can be calculated from the sums of water vapor and non-condensable gas pressures. The specific volume can be obtained from the flash fraction and the weighted average specific volumes of water vapor and liquid, which are expressible as explicit functions of temperature and composition. Non-condensable gases do not contribute to vapor volume. Thus, it is the same as listings in steam tables for pure water vapor. Dissolved solids cause a small increase in vapor volume, relative to saturation conditions, due to their effect on boiling pressures. The effect is manifest in the vapor as a kind of superheat.

Temperature Effects

The actual distance, ZA, between two points exactly one degree different in temperature is less than ZI for several reasons. Heat losses to the rocks, self-lift of the fluid in the wellbore, and increased kinetic energy of the expanding fluid all reduce the amount of new steam, compared to what would be generated by an ideal process. Significantly, the computed pressures are essentially unaffected.

Enthalpy loss to surrounding rocks occurs in proportion to the length of ZA. Thus, the residual part, TA, of the one-degree temperature drop that remains available for steam generation, is given by (3). L is the longitudinal rate of heat loss (Btu/hr-ft), R is the fluid mass rate of flow, and C is the fluid heat capacity.

$$TA = 1 - ZA(L)/RC \quad (3)$$

An explicit expression for ZA, (4), can then be derived.

$$ZA = ZI/[1 + ZI(L)/RC] \quad (4)$$

The bracketed term in (4) can be expanded to include the other components of temperature drop that detract from steam development. These are self-lift, TZ, and kinetic energy increases, TK, which are additive, as in (5).

$$ZA = ZI/[1 + ZI(L)/RC + TK + TZ] \quad (5)$$

Beyond the wellhead, where the fluid slows down, as in a steam separator, the TK term translates to a small, but real increment of steam, which is not the case for the other factors.

Mechanical-Dynamic Effects

A first approximation for the mass of material between two reference points is given in (2). However, the real pressure difference must incorporate a pressure that accelerates the fluid by just the amount required to sustain the mass flow rate in the face of increasing specific volume that occurs over the distance ZA. Because the speeds at each end of the interval can be calculated directly from the casing detail, mass rate, and specific volume, the mass acceleration, RK, can also be calculated. Similarly, fluid friction (drag against the pipewall), AF, is an additive acceleration force acting in the same direction as the others.

An accurate estimate of the fluid mass, MF, between the reference points is given by (6).

$$MF = DP/[G + RK + AF] \quad (6)$$

The acceleration used in this way provides a bridge between the conceptually mechanical pressures of friction and the conceptually chemical pressures of the vapors which support the fluid masses in the wellbore. This explicit connection between the mechanical and chemical aspects of two-phase flow appears to be absent from pressure-drop models. The significance of the chemist's view in this matter is that the pressures in the wellbore are definable by the principles of physical chemistry, This is the principal paradigmatic contrast with the traditional pressure-drop approach.

The Complete Model

The complete model consists of four kinds of factors; pressure, specific volume, temperature effects, and acceleration effects. The first two define an ideal case, the others account for non-ideality. They can be combined as in (7) which is based on (5) and (6), with ZI defined by (2).

$$ZA = ZI/[(1 + ZI(L)/RC + TK + TZ)(G + RK + AF)] \quad (7)$$

The terms in (7) can be computed by alternative methods. The most convenient involve temperature as the independent variable. Then, building a temperature profile for a wellbore becomes a straightforward calculational sequence without iterations. Profiles of all other factors and computed quantities can be constructed as well,

In this form, the model applies to substantially vertical wellbores without slip.

RESULTS

Parametric Studies

The details of two-phase flow in wellbores are affected by several factors. Some are resource specific such as temperature and composition of the fluid, reservoir pressure, and depth. Others are design parameters for a wellbore, such as casing diameters, casing profile, and wellhead pressure. How these factors interact comprise the basis for engineering design of wellbores.

A complete study of how all the factors, in their multiple variations, determine the pressure and temperature profiles in a wellbore, would be a modestly extensive work. A less ambitious presentation is given in Figures I through 8 which show the the effects of changing one factor through a broad range while holding all others constant. The factors and their ranges of values are given in Table 1. A set of standard values was used for the factors which were not varied in the computations for the figures. thus, curves in the figures are ideal-like because interactions are generally absent.

Table I: Factors For Construction Of Figures 1 to 8

Fig.	Factor	Range	Standard
I.	Resource Temperature	300 to 600 deg.F	500
2.	Production Rate	0.2 to 1.2 million lb/hr	0.35
3.	Wellbore Diameter	2 to 6 inches ID	8
4.	Fluid Friction, re. momentum transfer	3 to 100	0
5.	Productivity Index	125-4000 lb/hr psi	400
6.	Salinity	0 to 25 wt. percent NaCl	0
7.	Carbon Dioxide	0 to 2.1 wt. percent	0
8.	Enthalpy Losses	1 to 3000 Btu/hr ft	1

All of these parametric studies use a reference depth of 10,000 feet and static reservoir pressure of 4000 psia. The computer model begins from that reference, computing the flash depth by comparing computed vapor pressure with column pressure at successively shallower levels, as described in Ref. (2). An accounting is made for heat losses between the reference depth and flash point and their effect on brine density and vapor pressure, Some sets of the parametric curves show an interaction with this selection of reference depth.

Some of the factor ranges were chosen to include values which lead to impossible conditions. For example, Figure 1 shows that fluid cannot reach the level of the ground surface if flashing begins too deeply, compared to the fluid's initial temperature. The left-most curve shows that a 300-degree salt- and gas-free fluid appears to be limited to a production depth of about 1400 feet, even in the absence of enthalpy losses and frictional factors. In principle, fluid of any temperature has such a limitation. More curves would have shown it in Figure 1 if the flash depths had been set deeper. The variation of flash depths shown in Figure I is due mainly to the temperature effect on flash pressure.

Other interesting limitations involve dynamic factors. In Figure 2, production rates were modeled for a well of constant PI, thus higher rates involve increased drawdown$ and deeper flash points. All curves in the figure have the same shape, a consequence of setting enthalpy losses and frictional factors to zero for the computations. Choking of flow is due to requirements for increasing kinetic energy of the two-phase fluid as expansion progresses. This is the same aspect which, in Figure 3, is expressed by wellbores of different diameters carrying the same fluid production rates.

In both 2 and 3, choking is due to the inability of the brine to convert enough internal (thermal) energy into kinetic energy as required by the expansion and higher speeds in the upper parts of the wellbores. That limitation is distinct from a frictional limitation.

The frictional study of Figure 4 is based on a concept of mist flow in which some liquid droplets move along the pipewall in a saltational way. The saltation involves a drag due to momentum transfer when the main fluid stream accelerates droplets upon their release from the pipewall. The factor values refer to the mean lengths of paths taken by droplets during their brief flights. Since the standard wellbore diameter and production rate chosen for this figure avoid kinetic factors, ala Figs, 2 and 3, Figure 4 shows a kind of choking due purely to frictional (momentum transfer) effects.

In Figure 5, as in Figure 2, all the curves are the same shape, differing only in regard to flash depth. This rather staid result is, in a minor way, due to the artificial zeroing of enthalpy losses and friction. But, more importantly, the sameness of shape expresses a fundamental basis of the model. Namely, that the fluid expansion, hence the wellbore profile, is firstly a result of fluid properties, and is only moderated by the mechanical aspects of wellbores.

The pressure-drop models have it the other way around. This aspect, more than any other, shows the temperature-drop paradigm to be fundamentally different from the pressure-drop approach. They decidedly are not alternative expressions of the same concepts.

Figure b shows effects of brine salinity on the profiles. Depths of initial flashing are different for two reasons. The bubble point pressures, which are moderated by the salt contents, cause incremental differences in the drawdown-PI relationship for the uniform production rates used.

More subtle are the effects of choices for reservoir static pressure and reference depth, 4000 psia at 10,000 feet. Because pressure gradients in the modeled liquid columns are also functions of salt content, the bubble points for saltier water appear successively deeper, in Figure 6, due to the long distances fram the reference depth. If a shallower reference depth were chosen, the different gradients would operate on shorter lengths of one-phase fluid columns. The relative distances between bubble points for successive curves would then be different than shown in Figure 6. The order of curves in the figure could even be reversed.

Carbon dioxide has two manifestations which are shown :in Figure 7. Higher bubble point pressures due to larger amounts of carbon dioxide cause initial flashinq to be deeper in a wellbore. The carbon dioxide's contribution to fluid self-lift results :in higher temperatures at shallow depths. Those effects are un opposition, so a greater net temperature at the wellhead results only when the bubble point is suitably deep.

Enthalpy losses, Figure 8, cause a general sagging of the profiles toward lower temperatures and pressures. Figure 8 is constructed as if there were no losses below the point of initial flashinq. If losses in the one-phase zone were to be added, points of initial flashinq would be progressively shallower for greater heat loss assignments and pressures would be less. The curves could cross, as in Figure 7, depending on the extent of interaction between the one-phase pressure gradient and distance between the deep reference level and flash point.

Real Wellbores

Good fits to downwell data fror real wells can be obtained by manipulating the hard-to-quantify factors of heat loss and friction. Figure 9 is an example.

DISCUSSION

The computational simplicity of the terperature drop model is much improved by expressing the terms of equations (2) and (7) as explicit functions of temperature and salt content, as done in (1), thereby avoiding tables. For sore factors, such as fluid speed and kinetic energy calculations, a second level of computation is required. It is based on specific volumes of the phases and weight fractions that are explicit functions of temperature, etc.

Once the cherical equations are available for brine properties, the equations for profile computations can be easily derived from geometrical considerations. Thus, to a very large degree, the model is based on first principlrs.

Two-Phase Fluid Friction

The friction term, AF in (6) and (7), can be computed on any basis one pleases. Since friction is not an atlor-scale phenorenon, this chemically inclined author prefers to view that drag force as a momentum transfer occurrinq from the faster two-phase stream to droplets of liquid that tear loose from the slower filr that covers the pipe wall. Downstream, the accelerated drdplets impact on the pipe wall and their momentum is lost.

The effect is like saltation (ref. 3). The result is a drag force directly proportional to the amount of liquid participating in the saltation and also to the difference in speed between fluid stream and liquid film. It is inversely proportional to the average lenqth of the saltational paths taken by the droplets.

Because this concept of draq relates to momentum of the droplets, not their kinetic energy, it involves the fluid speed to the first power, not the second. A concept of frictional heatinq, dependent on the square of fluid speed, may be appropriate for cooler liquids wherein heatinq represents a loss of useful energy, However, in the geothermal case, fluid heat is the sine qua non. Since most of the work of movinq the fluid through and up the wellbore derives from its own internal energy, a speed-squarred concept of friction seems less appropriate.

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FIGURE: 1

PROFILES DUE TO A RANGE Of RESOURCE TEMPERATURES
300 to 600 degrees F by 50°

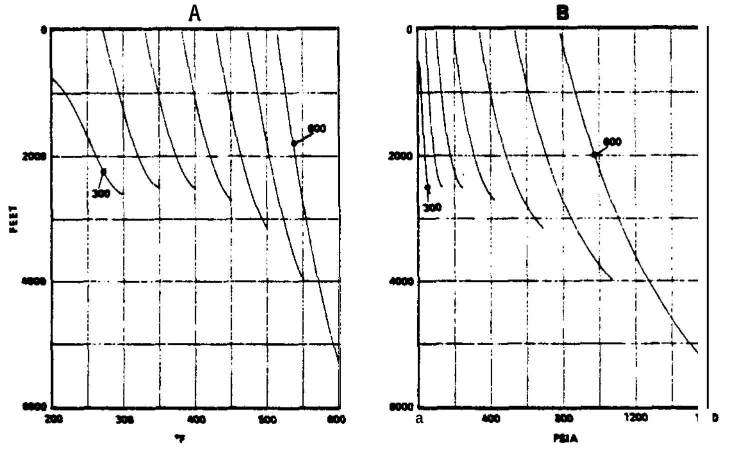

FIGURE: 2

PROFILES DUE TO A RANGE OF FLUID PRODUCTION RATES
0.2 to 1.2 million pounds per hour by 0.2 MPPH

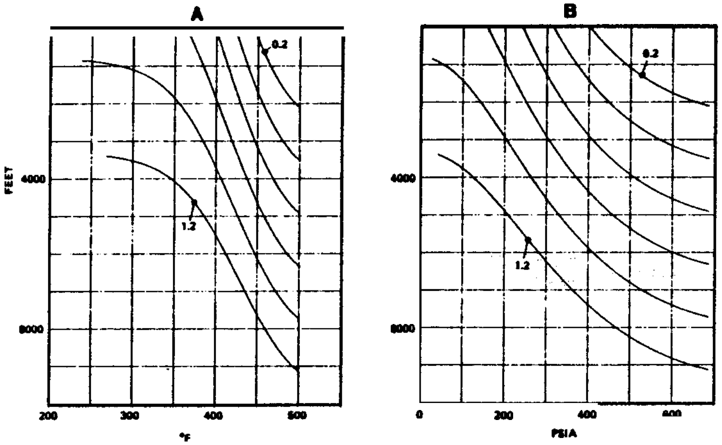

FIGURE: 3

PROFILES DUE TO A RANGE OF WELLBORE INTERNAL DIAMETERS
2 to 6 inches by 1 inch

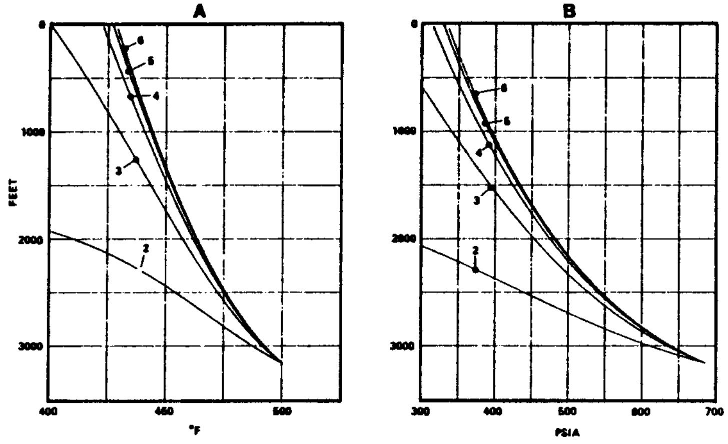

FIGURE: 4

PROFILES DUE TO A RANGE OF FLUID FRICTION (MOMENTUM) FACTORS
3 to 100 by 2X

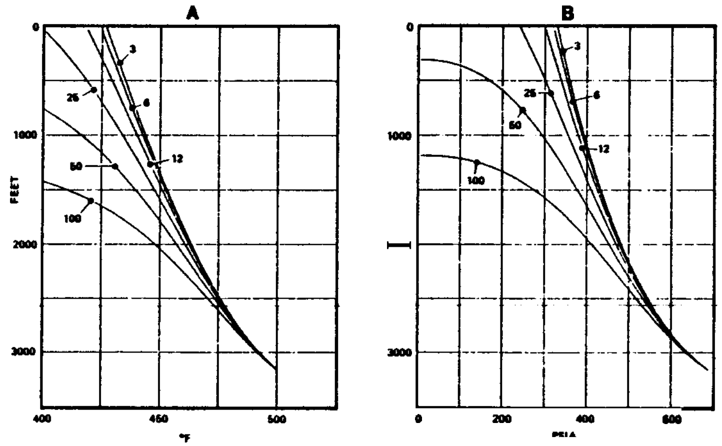

FIGURE: 5

PROFILES DUE TO A RANGE OF PRODUCTIVITY INDEX
125 to 4000 pounds per hour per PSI by 2X

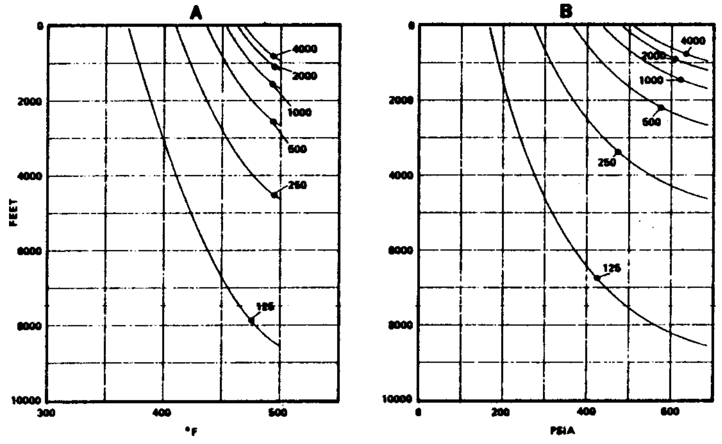

FIGURE: 6

PROFILES FOR A RANGE OF SALT CONTENT
0 to 25 perçent (wt) by 5 percent

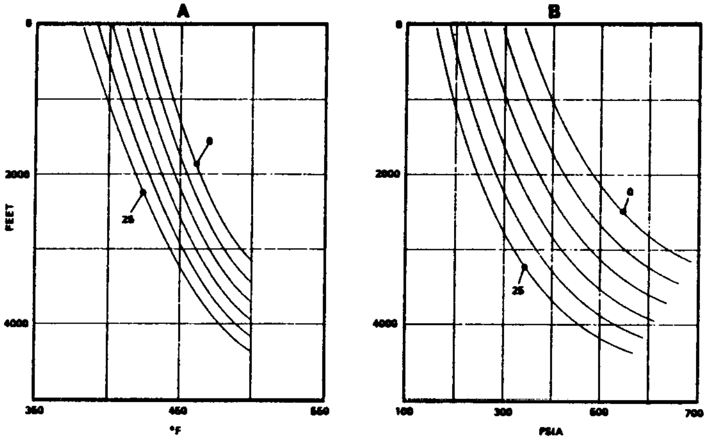

FIGURE: 7

PROFILES FOR A RANGE OF CARBON DIOXIDE CONTENTS
0 to 21 parts per thousand (wt) by 3 PPT

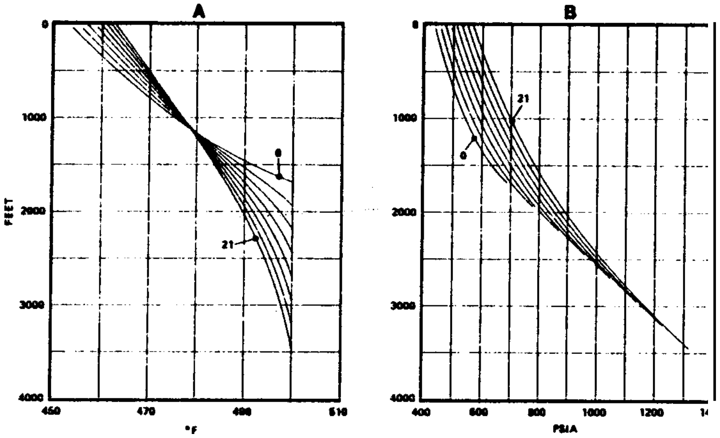

FIGURE: 8

PROFILES DUE TO A RANGE OF WELLBORE ENTHALPY LOSSES
1 to 3000 Btu/hr-ft by 500

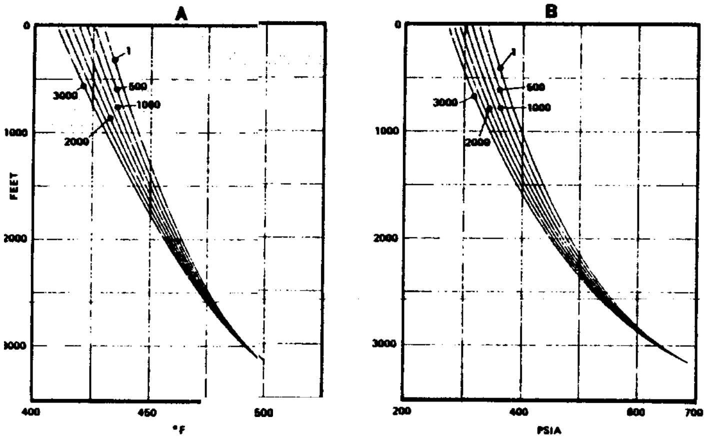

FIGURE: 9

COMPUTED FITS TO FIELD DATA
● DATA — CALCULATION