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ANALYSIS OF FLOW DATA FROM SEVERAL BACA WELLS

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Abstract Analyses are presented of the downhole pressure buildup data for wells located in the Redondo Creek area of the Baca Geothermal Field. The downhole drilling information and pressure/ temperature surveys are first interpreted to locate zones at which fluid enters the wellbore from the fractured formation and to estimate the initial reservoir temperature and pressure in these zones. Interpretation of the buildup data for each well considers wellbore effects, the CO_2 content of the fluid and differentiates between the single-phase and two-phase portions of the data. Different straight-line approximations to the two portions of the data on the Horner plot for a flow test yield corresponding estimates for the single and two-phase mobilities. Estimates for the formation kh are made for the wells.

Introduction The Baca Geothermal Field is located in the Valles Caldera in north central New Mexico, 60 miles north of Albuquerque, and about 35 miles northwest of Santa Fe. Analysis of the downhole data from wells drilled in the Redondo Creek area of tne field indicates that the bulk of the formation permeability is in a fracture network. Consequently, the performance of a well depends largely upon whether it intersects one or more fractures, how large each intersected fracture is and the degree to which it is connected to the rest of the network. The reservoir pressures identified from the downhole analysis define a vertical gradient of 0.348 psi/ft.

Chemical analyses of the discharge fluids from Baca wells indicate that the reservoir fluid is of low salinity ($\leq$ 8,000 ppm) with an incondensible gas content (principally CO_2) of about 0.4 to 1.5 percent by mass (α = 0.004 to 0.015). The effect of the incondensible gas content on the fluid state may be examined using an equation of state for a mixture of pure water and carbon dioxide (Pritchett, et al. [1981]). Figure 1 illustrates the effect in p-T space for α = 0.01. The probable extent of the initial two-phase region in the Baca reservoir and the extent to which the wells will induce flashing in the formation upon production are very sensitive to the CO_2 content of the fluid.

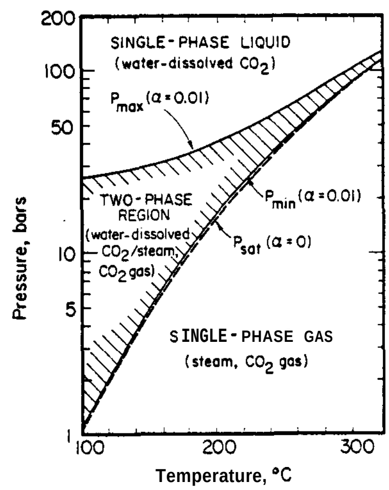

Figure 1. Phase diagram for water with CO_2 mass fraction α=0.01. Saturation curve for pure water (α=0) is dashed.

The S^3 reservoir simulator CHARGR was recently employed in a series of radial flow calculations to investigate the response of initially single-phase and initially two-pnase reservoirs undergoing production or injection from a single well (Garg and Pritchett [1980]). Figure 2 shows the Horner plot for the simulated buildup history of an initially single-phase reservoir that undergoes flashing upon production. The initial buildup behavior (wellbore storage effects were not simulated) is governed by the two-phase region of the reservoir; the slope on the Horner plot of the curve yields a value for the total kinematic viscosity ν_t which is characteristic of the two-phase region created during drawdown. The detailed calculations show that the pressure buildup is accompanied by the propagation of a condensation front, originating at the well, into the formation; the condensation front eventually engulfs the

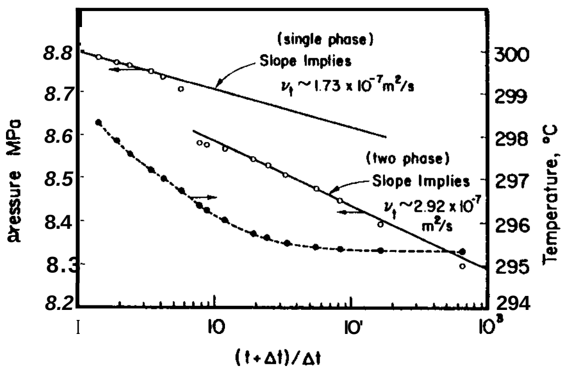

Figure 2. Pressure and temperature buildup data for Case B-1 simulated well test (Garg and Pritchett [1980]).

entire two-phase region after which the buildup behavior is essentially that of a single-phase fluid. The two-phase buildup extends over a full log cycle; the slope of this straight line implies a kinematic viscosity which is in fair agreement with the actual two-phase value. The single-phase buildup in this case extends over less than one-half cycle; the slope of this straight line implies a kinematic viscosity which is about 40 percent larger than the actual single-phase value. This example, and other cases treated, illustrate the importance of selecting the correct straight line.

We have used the results of the numerical simulations to provide guidance in our interpretation of the flow data from several Baca wells. The interpretation considers the effects of the CO_2 content and fracture permeability of the reservoir. The analysis also accounts for the fact that the downhole **pressure/temperature** gages are usually located several hundred feet from the primary production zone. In the following we will present representative buildup analyses of data from two Baca wells.

Well Baca No. 4 Figures 3 and 4 present selected temperature and pressure profiles recorded in well B-4. Survey S8 was taken prior to any production testing, but the well had been deepened from 5048 ft (4301 ASL) to 6378 ft (2987 ASL) five weeks earlier. Temperature survey S11 was made 17 days after a 9-day production test and is in close agreement with S8 for depths less than 5000 ft. For very long shutin times the measured temperatures (profiles S24 and S40) are much higher than for the shorter shutin times (profiles S8 and S11) except for close agreement at the bottom of the hole. This is attributed to the influx of hot fluid from a minor entry near the bottom of the well. Survey S16 was recorded two days after shutin following a 64-day drawdown

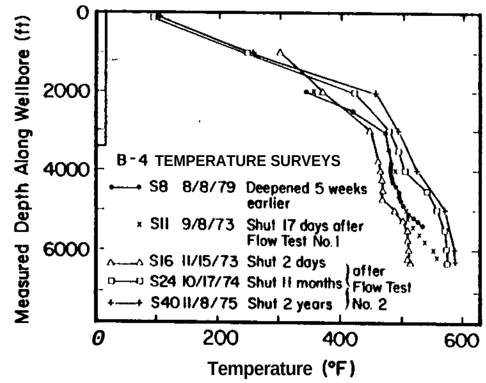

Figure 3. B-4 temperature surveys before, during and after Flow Test No. 2.

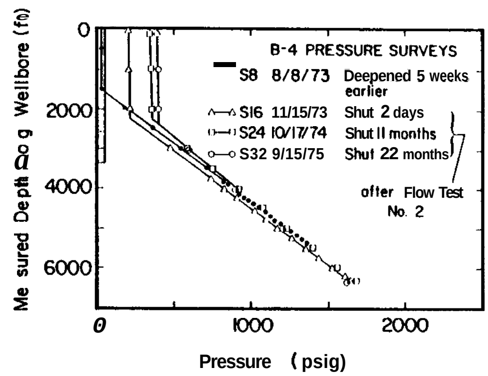

Figure 4. B-4 pressure surveys before, during and after Flow Test No. 2.

period. The primary production is apparently located at ~ 4800 ft (4546 ASL); the reservoir rock is cooled by the flashing of the fluid within the production zone. The corresponding pressure profile (S16 in Figure 4) shows that the fluid in the wellbore two days after shutin is liquid below 2100 ft. The long-term stable profiles (S24 and S32) cross the early time profile (S8) at ~ 4500-5000 ft. Pressure equilibrium between the wellbore and reservoir fluid is maintained at the zone of primary permeability ~ 4800 ft.

In summary, the zone of primary permeability in B-4 is located at ~ 4800 ft (4546 ASL) with minor entries located near the wellbottom and at shallower depths noted during drilling. The initial temperature and pressure at 4800 ft are estimated to be 1170 psig (~ p(a) = 81.4 bars)* and ~ 500°F (260°C).

Although B-4 has been flow tested three times, downhole measurements are available only for the buildup period following Flow Test No. 2 (9/10/73-11/13/73). During the 64-day drawdown portion of this test the fluid flowed to a separator vessel and the steam and water phases were measured individually. After 50 days, the flow rate stabilized with a wellhead pressure of 120 psig and a separator pressure of 113 psig (Hartz [1976]). At separator conditions the steam fraction and total fluid enthalpy were reported to be 27.5 percent and h_t = 556.1 BTU/lbm. The mass flow rate and the duration of Flow Test No. 2 are taken as

$$M = 172{,}500 \text{ lbm/hr} \sim 21.73 \text{ kg/s}$$
$$t = 1538 \text{ hours.}$$

Figure 5 shows a semi-log plot of the buildup data recorded by Union at a depth of ~ 6350 ft (3000 ASL). Since the measurements

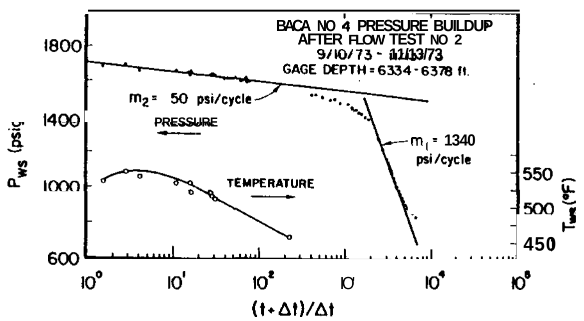

Figure 5. B-4 pressure and temperature buildup following Flow Test No. 2.

were made so far below the primary production zone at 4800 ft (4546 ASL), we must account for the pressure difference in the data interpretation.

During drawdown the wellbore is filled with two-phase fluid which enters from the primary production zone. The reservoir rock is cooled by the flashing of the fluid within the production zone. After shutin the temperature within this zone recovers along with pressure until condensation occurs; it subsequently recovers slowly, primarily by conduction. From the temperature survey made on 11/15/73 (S-16) we estimate the temperature in the wellbore at 4800 ft (4546 ASL) after condensation is initiated to be ~ 464°F (240°C).

The CO_2 content of the discharge fluid from B-4 has been measured to be 0.85–1.1 percent (a = 0.0085–0.011). Although the in-situ value may be different (Pritchett, et al. [1981]), we assume for the moment that a = 0.01. Then according to Figure 1,

* Here and in the sequel we add 10 psi (0.7 bars) to the gage pressure to correct for tne atmospheric pressure at~9000 ASL.

the pressure required to ensure that the 464°F (240°C) wellbore fluid be single-phase liquid is P_{max} = 812 psia (56 bars). Correspondingly, the recorded shutin pressure at ~ 6350 ft (3000 ASL) must satisfy the inequality p_{ws} > 812 + 0.35 (4546–3000) = 1353 psia = 1343 psig

This value is attained at ~ 43 minutes after shutin; hereafter there is a constant hydrostatic head of 541 psi between the gage pressure and the corresponding pressures in the production zone. Only the single-phase portion of the Horner plot (Figure 5) may be used in this case (*a* = 0.01) in evaluating formation properties of the production zone.

Further, if the CO_2 content were 1 percent (a = 0.01), then from Figure 1 we see that the initial reservoir conditions (81.4 bars, ~ 260°C) would correspond to single-phase liquid. During drawdown the formation fluid flashes in the vicinity of the wellbore and the flash front propagates laterally into the producing zone. After shutin, condensation commences but a two-phase region created during drawdown would not return to single-phase liquid until the pressure builds up to the value of P_{max} associated with ~ 260°C, i.e., P_{max} = 67 bars (972 psia). The corresponding pressure at the recording depth of 6350 ft (3000 ASL) is given by p_{ws} = 972 + 0.35 (4546–3000) = 1513 psia = 1503 psig. This value is close to the transition pressure (~ 1575 psig) between the two-phase and single-phase behavior shown in Figure 5.

We note in passing that if we had ignored tne presence of CO_2 and assumed the fluid to be pure water (α_0 = 0), we would compute that the producing zone at 4800 ft would recover from two-phase to single-phase water when the pressure builds up to p_{ws} = 1212 psig. This value is considerably below the observed transition pressure (~ 1575 psig).

Because of the uncertainty in the values of a and the initial temperature in the production zone, it is of interest to determine the values of these parameters which correspond to the two-phase to single-phase transition pressure indicated by the Horner plot. The equation-of-state for CO_2/water mixtures (Pritchett, et al. [1981]) has been used to determine those points (α_0, T_0) which correspond to a pressure in the production zone of P_{max} = 1575 - 541 = 1034 psig = 1044 psia (72 bars). The estimated initial temperature (T_0 ~ 500°F) corresponds to the higher measured value of CO_2 in the discharge fluid (α_0 = 0.011) whereas the lower measured value (α_0 = 0.0085) corresponds to an intial temperature of T_0 ~ 512°F (~ 267°C). These values are within the uncertainties of the measurements.

The slope m_2 = 50 psi/cycle = 3.44 x 10^5 Pa/cycle in the single-phase portion of the Horner plot reflects the buildup behavior in the production zone and extends over two full log cycles. It can, therefore, be used to estimate the kinematic mobility-thickness product from the relation

$$\frac{kh}{\nu_t} = \frac{1.15\,\dot{M}}{2\,\pi\,m} = \frac{1.15\,(21.73)}{2\pi(3.44\times10^5)} = 1.16\times10^{-5}\ \text{ms}$$

To estimate the formation kh product we need an approximate value for the total kinematic viscosity of the reservoir fluid during the single-phase portion of the buildup response. We use the viscosity of liquid water at the initial conditions of the producing zone (81.4 bars, 260°C), $\nu_t = \nu_\ell = 1.315\times10^{-7}\ m^2/s$ and compute

$$kh = 1.52\times10^{-12}\ m^3 = 5050\ \text{md-ft}.$$

Well Baca No. 20 The temperature surveys, in Figure 6 especially S5 and S10, indicate that relatively low temperature fluid enters the wellbore at approximately 4000 ft (5165 ASL). This implies that the primary production zone is located at 4000 ft and the fluid entering the wellbore at this depth during buildup subsequent to Flow Test No. 4 has been cooled by flashing within the formation. Below 5000 ft (4237 ASL) there appears to be conductive heating of the wellbore fluid (see S5 and S10).

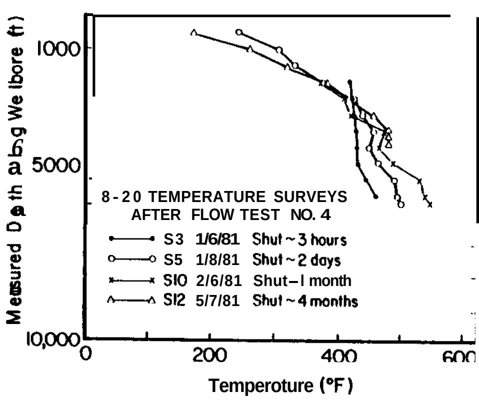

Figure 6. 8-20 temperature surveys following Flow Test No. 4.

The initial pressure at 4000 ft is estimated from S2 (not shown) and S12 (Figure 7) to be ~ 975 psig (p(a) = 67.9 bars). Since no stable temperature profile is available, we extrapolate S12 from 3500 ft to estimate the initial temperature at 4000 ft to be ~ 485-515°F (252-268°C). From S3 the temperature in the primary production zone at 4000 ft (5165 ASL) is estimated to be reduced to ~ 432°F by the in-formation flashing.

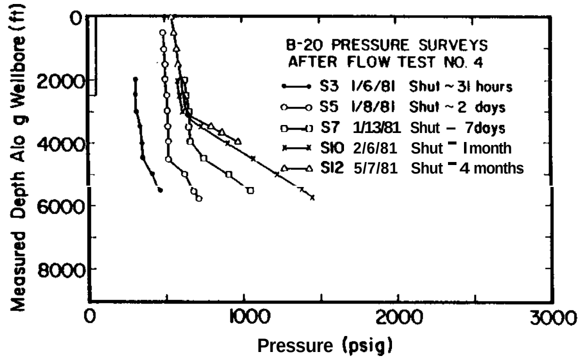

Figure 7. 6-20 pressure surveys following Flow Test No. 4.

Four flow tests have been performed on 6-20 but only Flow Test No. 4 (9/24/80-1/6/81) was of sufficient duration (104 days) and with sufficient pressure transient measurements to warrant analysis. During the flow test the well was flowed through a vertical separator. The wellhead pressure and total flow rates varied over the test period but stabilized over the last two months. For the purposes of analysis we use

$\dot{M}$ = 56,100 lbm/hr (averaged over last 10 days)

~ 7.06 kg/s

t = 2,653 hours (equivalent production time)

Time t is calculated by dividing the cumulative fluid mass produced during the 104-day Flow Test No. 4 (148,830,000 lbm) by the total mass flow rate averaged over the last ten days of the production.

Figure 8 presents a semi-log plot of the pressure buildup at a depth of 4500 ft (4700 ASL) where most of the downhole recordings were made. Since the primary production is

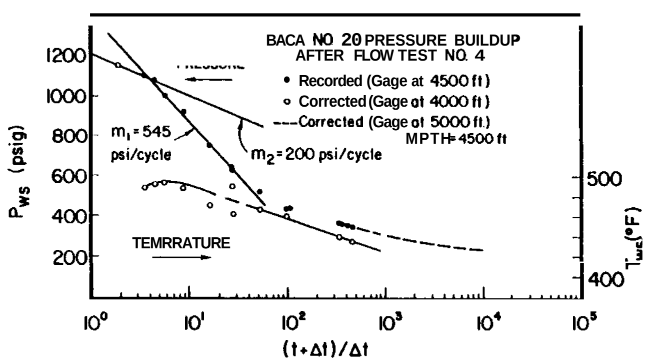

Figure 8. 6-20 pressure and temperature buildup following Flow Test No. 4.

at 4000 ft and the bulk of the pressure data were recorded at 4500 ft, it is necessary to account for the pressure difference in interpreting the data. The pressure profiles in Figure 7 show that the wellbore fluid is two-phase during the buildup period. The fluid below 4500 ft is two-phase at three hours (S3) and two days (S5) after shutin. After seven days (S7) the fluid below 4500 ft is single-phase liquid, the fluid above 4000 ft is single-phase gas and there appears to be a two-phase section at 4000-4500 ft. After one month there is liquid below 3000 ft with a gas cap above this depth.

Since the wellbore pressure at the gage depth must be corrected by different amounts at different buildup times, we have replotted the Horner plot in Figure 9. The data points at 4000 ft (5165 ASL) recorded during profile surveys are indicated as are the estimates made from surveys in which recordings were only made at 4500 ft (4700 ASL). In this case the estimates for the primary production depth (4000 ft) contain corrections which account for changes in the wellbore state with changes in buildup time. From the corrected plot (Figure 9) we see that the transition from slope m_1 to m_2 is actually completed at $p_{ws} > \sim 900$ psig rather than the much larger apparent value inferred from Figure 8.

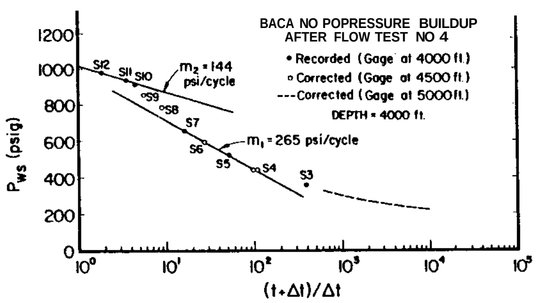

Figure 9. Corrected 6-20 pressure buildup following Flow Test No. 4.

A CO_2 mass fraction of 1.47 percent has been measured in the discharge fluid from well 6-20. This is higher than that measured in all but one other well and may be higner or lower than the in-situ value (Pritchett, et al. [1981]). If we assume that the CO_2 content in the primary production zone is in fact the same as measured in the discharge fluid, then the zone at 4000 ft would be initially two-phase for any temperature within our range of uncertainity (- 252-268°C). According to the equation-of-state for CO_2/water mixtures, at 252°C the initial in situ gas saturation would be S_g = 0.077 whereas the temperature of 268°C would imply S_g = 0.409. In this case, the transition from slope m_1 to slope m_2 in Figure 9 would merely reflect the recovery of the production zone to its initial conditions.

On the other hand, if we assume the change in slope corresponds to a transition from two-phase to single-phase behavior during buildup, then the equation-of-state for CO_2/water mixtures may be used to determine the set of permissible points (T_o, α_o) for which P_{max} = 62.8 bars (910 psia = 900 psig). A value of T_o = 252°C would imply α_o = 0.01 whereas a value of T_o = 268°C would imply α_o = 0.003.

Because of the uncertainty in α_o and T_o we cannot establish if the primary production zone is initially single-phase liquid (e.g., P_o = 67.9 bars, T_o = 252°C, α_o = 0.01) or initially two-phase (e.g., P_o = 67.9 bars, T_o = 252°C, α_o = 0.0147). In either case, however, the slope m_1 in Figure 9 approximates the two-phase portion of the pressure build-up for a full log cycle and this portion of the data can be used to infer formation properties.

From the value of m_1 = 265 psi/cycle (18.3 x 10^5 Palcycle) we can calculate the corresponding value of the two-phase kinematic mobility-thickness product

$$\frac{kh}{\nu_t} = \frac{1.15\ \dot{M}}{2\pi m_1} = \frac{1.15\ (7.06)}{2\pi(18.3 \times 10^5)} = 7.06 \times 10^{-7}\ \mathrm{ms}$$

To estimate the formation kh product we first note that during the last ten days of Flow Test No. 4 the wellhead pressure and effective (total) enthalpy of the produced fluid were essentially constant: WHP = 116 psig; h_t = 794.3 BTU/lbm. We have used these values, and an isenthalpic model for two-phase flow in the wellbore that assumes no slippage between the liquid and gas components, to estimate the downhole flowing conditions during the final ten days of drawdown. The calculated pressure at 4000 ft (5165 ASL) is p_{wf} = 180 psig (p(a) = 13.1 bars) and the corresponding downhole flowing kinematic viscosities of the liquid and gas components and the mass ratio of the mixture entering the wellbore are as follows:

$$\nu_\ell = 1.59 \times 10^{-7}\ \mathrm{m^2/s}$$

$$\nu_g = 2.29 \times 10^{-2}\ \mathrm{m^2/s}$$

$$m_g/m_\ell = 1.12$$

The linearized equations in the Appendix can now be used to estimate ν_t. From Eq. (A-5) we compute

$$\frac{k_{rg}}{k_{r\ell}} = 1.12\ \frac{22.9}{1.59} = 16.2$$

If we assume that the flow within the formation is primarily through a fracture network then from Eq. (A-6) we can calculate the individual relative permeabilities $k_{rg} = 0.942$ and $k_{r\ell} = 0.058$. From Eq. (A-2) we estimate the total kinematic viscosity during the last ten days of drawdown.

$$\nu_t = \left(\frac{0.058}{1.59 \times 10^{-7}} + \frac{0.942}{2.29 \times 10^{-6}}\right)^{-1}$$

$$= 1.29 \times 10^{-6} \ m^2/s$$

We assume that the kinematic viscosity during the two-phase portion of the buildup is approximated by this value. An estimate of the formation kh product from the two-phase portion of the buildup data can now be made.

$$kh = (1.29 \times 10^{-6}) \ (7.06 \times 10^{-7})$$

$$= 90.8 \times 10^{-14} \ m^3 = 3030 \ \text{md-ft}$$

Discussion The objective of this paper was to illustrate an analysis procedure which is based on the synthesis of field measurements and theoretical results in interpreting geothermal well flow data. The interpretation given here for well B-4 is based on the single-phase portion of the buildup data and yields a value of kh which is in reasonable agreement with the value of 4207 md-ft estimated by Hartz [1976] from a conventional Horner plot analysis. The interpretation given for well 6-20, however, is based on the two-phase portion of the buildup data and a correction of the Horner plot to account for the fact that gage is located several hundred feet from the primary production zone. A conventional Horner analysis would not be applicable.

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Appendix Several authors (e.g., Garg and Pritchett [1980]) have obtained approximate analytical solutions for a geothermal reservoir undergoing two-phase production at a constant rate. In these studies the balance equations for radial two-phase flow in porous media are linearized by assuming that the total and the component kinematic mobilities are related as follows:

$$\left(\frac{k}{\nu}\right)_t = \frac{k\,k_{r\ell}}{\nu_\ell} + \frac{k\,k_{rg}}{\nu_g} \tag{A-1}$$

$$\frac{1}{\nu_t} = \frac{k_{r\ell}}{\nu_\ell} + \frac{k_{rg}}{\nu_g} \tag{A-2}$$

Given the flowing enthalpy h_t of the two-phase mixture, it is also possible to obtain the separate kinematic mobilities.

$$\frac{k\,k_{r\ell}}{\nu_\ell} = \left(\frac{k}{\nu}\right)_t \left[\frac{h_g - h_t}{h_g - h_\ell}\right]; \quad \frac{k\,k_{rg}}{\nu_g} = \left(\frac{k}{\nu}\right)_t \left[\frac{h_t - h_\ell}{h_g - h_\ell}\right] \tag{A-3}$$

The expression

$$h_t = m_g h_g + (1-m_g) h_\ell \tag{A-4}$$

relating the total and fluid component enthalpies may be used with Eqs (A-3) to write

$$\frac{k_{rg}}{k_{r\ell}} \frac{\nu_\ell}{\nu_g} = \frac{m_g}{m_\ell} = \frac{m_g}{1-m_g} \tag{A-5}$$

Here m_g and $1-m_g$ are the gas and liquid components of the fluid flow.

If we assume that the flow within the formation is primarily through a fracture network, then

$$k_{r\ell} + k_{rg} = 1 \tag{A-6}$$