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Pressure-Dependent Water Loss From a Hydraulically Stimulated Region of Deep, Naturally Jointed Crystalline Rock

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ABSTRACT

The rate of water loss from a hydraulically stimulated region of naturally jointed crystalline rock is shown to be dependent on both the pressure and the pressure gradient. However, there is a threshold pressure above which the rate of water loss increases much more rapidly. Above this threshold pressure, further growth and extension of the previously stimulated region occurs due to additional dilation and shear displacement of peripheral joints, as evidenced by greatly increased microseismic activity at the boundaries of the region. Therefore, the increased water loss at pressures above this threshold pressure is primarily due to fluid storage within the newly stimulated region, rather than to increased permeability losses at the boundaries.

Introduction

In conjunction with the Los Alamos National Laboratory's Hot Dry Rock (HDR) Geothermal Energy Project, two flow tests recently have been conducted on the deeper Phase II HDR reservoir at the Fenton Hill test site in north-central New Mexico. These flow tests have been performed at injection pressures varying from 24 MPa to 31 MPa,* and at rates of from 6 l/s to 18.5 l/s. The first of these flow tests, referred to as the Initial Closed-Loop Flow Test (ICFT), was conducted during a 30-day period from 19 May - 18 June 1986. The second flow test, referred to as Experiment 2074, was conducted during a 7-day period from 2 to 9 December 1987. For each flow test, the transient water loss rate was measured as a function of pressure, and the pumping-induced seismicity was monitored.

These two flow tests were intended to provide essential information needed in designing the surface flow system and planning for the forthcoming one- to two-year circulation test of the deeper Phase II HDR reservoir at Fenton Hill, referred to as the Long-Term Flow Test (LTFT). Two of the most important parameters needed for designing the LTFT surface system are the maximum allowable surface injection pressure, and the anticipated reservoir water loss rate under long-term operating conditions. After reinflation, reservoir water loss results from two dominant mechanisms: (1) flow of water out of the stimulated region through the natural permeability of the surrounding rock, and (2) water storage within newly sti-mulated regions of rock at the boundaries of the reservoir. To aid in understanding tran-sient reservoir behavior, one of the primary requirements for the LTFT is that the reser-voir volume remain constant, to allow accurate measurements of reservoir water loss, fluid volume, impedance, heat extraction, and power production throughout the test.

Since one of these flow tests was essentially aseismic, while the other was highly seismic, it is apparent that there exists sufficient data to estimate the maximum surface injection pressure that would preclude reservoir growth. In this context, reservoir growth is defined as the stimulation, through hydraulic pressurization, of the joints bounding the previously created reservoir region, as determined from the occurrence of microseismic signals associated with the extension of the principal sets of shear joints which provide the primary interconnecting flow paths within the reservoir.

In order to predict the long-term water loss from the reservoir due to permeation at the boundaries, it is necessary to first model the pressure-dependent (i.e., effective-stress-dependent) permeability of the surrounding rock, and then determine the coefficients in this model from available reservoir water loss rate data. (An entire sequence of water-loss-rate measurements as a function of reservoir pressure is now planned for this spring.) A principal motivation for these field measurements and associated modeling is the assertion by some that reservoir water loss will be a major problem in developing and implementing the HDR Geothermal energy concept.

Selection of a Pressure-Dependent Permeability Model

Of the several available pressure-dependent permeability (or joint deformation) models, the one that has been found to best represent both the elastic moduli and permeability/porosity of microcracked and jointed crystalline rock is that of Gangi and Carlson (Gangi, 1978 and 1981; Carlson and Gangi, 1985). Unlike

* All pressures and stresses given in this paper are as measured at the surface (i.e., above hydrostatic).

the linear dependence of the modulus on pressure (i.e., stress) as determined from the joint deformation models of Goodman (1976), Greenwood and Williamson (1966), and Swan (1983), the deformation modulus of Gangi and Carlson asymptotes to a constant value at high confining stress. This limiting modulus behavior, where the modulus for the cracked rock approaches that of the linearly elastic unflawed rock at elevated stresses (of the order of 70 to 120 MPa), would be expected to better represent the in situ behavior of typically discontinuous deep crystalline rock masses, and is in agreement with numerous laboratory measurements (e.g. Brace, 1965; and Walsh and Brace, 1973). Limited field measurements in our Phase II HDR reservoir at Fenton Hill suggest that the Gangi "bed-of-nails" model adequately represents the pressure-dependent permeability of the microcracked and naturally jointed crystalline reservoir rock, at least for effective stresses in the range of 0 to 30 MPa. This permeability model is (Gangi, 1978)

$$k(P) = k_o[1-(P/P_1)^m]^3 \tag{1}$$

where P is the effective normal stress (total stress minus pore fluid pressure) across the joint, k_o is the zero-pressure (i.e., zero-effective-stress) permeability, P_1 is the normal stress at which the joints or microcracks are essentially closed, and m is a constant ($0<m<1$) which characterizes the joint surface asperity height distribution function.

Other, more complicated models are available which allow the permeability to asymptote to a finite, but very small residual value at high stress. Although these models are possibly more appropriate over the full range of in situ stresses, they are not necessary for the anticipated stress conditions associated with an HDR reservoir, where the main objectives are to model the reservoir flow behavior and the far-field permeable outflow, under conditions of moderate to low effective confining stress.

The Gangi permeability model, Eq. 1, explicitly assumes the validity of the cubic law* relating the joint permeability to the joint porosity for constant planar area joints. Therefore

$$\phi(P) = \phi_o[1- (P/P_1)^m] \tag{2}$$

where ϕ_o is the equivalent zero-stress porosity. Witherspoon et al. (1980) report extensive measurements on fluid flow through artificial tensile fractures in granite, basalt, and marble which confirm the validity of the cubic law for fracture apertures down to 4 μm, normal stresses up to 20 MPa, and a range of flow rates that typically spans about 5 decades.

As an example of the applicability of the Gangi model, the stress-displacement behavior of a natural joint in crystalline rock has been selected from the literature. Figure 1 shows the nonlinearly elastic deformation of a joint in a large block (0.3 m across) of Red granite as measured by Sun et al. (1985). Fitting the displacement form of Eq. 2

$$w(P) = w_o[1 - (P/P_1)^m] \tag{3}$$

to the data shown in Fig. 1 for an assumed P_1 of 25 MPa gives

$$w(P) = 0.22[1 - (P/25)^{.364}] \tag{4}$$

with a total joint closure of 0.22 mm at 25 MPa. Table I compares the smoothed data from Fig. 1 to the displacements as calculated from Eq. 4.

Table I

Comparison of Measured and Calculated Joint Widths as a Function of Normal Stress

Normal Stress MPa	Measured Joint Width, mm	Calculated Joint Width, mm (Eq.4)
0	0.220	0.220
2	0.132	0.131
6	0.086	0.088
10	0.062	0.062
25	(assumed zero)	0.000

Predicted Reservoir Peripheral Water Loss Rate vs. Pressure

For the long-term operation of a pressurized HDR Geothermal reservoir, a very important parameter is the rate of water loss due to permeation at the boundaries of the pressure-dilated (i.e., stimulated) region. This water loss to the lower-pressure far-field region will most probably be through the interconnected microcrack fabric in the surrounding unstimulated rock. The fluid will permeate outwards, generally in a direction parallel to the least principal earth stress, and normal to the longer axes of the ellipsoidal-shaped reservoir region. Therefore, the permeable outflow will be controlled primarily by the intermediate earth stress. However, the unopened extensions of the joints comprising the HDR reservoir, if not completely filled with secondary mineralization, may afford additional paths for water loss to the far field.

Figure 2 shows the measured matrix permeability (heavy lines) as a function of effective confining stress (or pressure) for three representative core samples obtained from the Fenton Hill test site (Duffy, 1980). Note that we do not presently know the relationship

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* Based on the Reynolds equation for laminar flow between two parallel plates separated by a distance w, where the flow rate, for a given pressure gradient and fluid viscosity, is proportional to w^3.

between the stress-relieved core sample permeabilities (which are seen to vary by almost an order of magnitude) and the effective in situ permeability for the actual rock mass with included joints. For initial analysis, the permeability curves of Fig. 2 were averaged (the dashed curve) and then fitted with an equation of the form of Eq. 1

$$k(P) = 1.6 \times 10^{-18}[1 - (P/117)^{.285}]^3 \quad (5)$$

(The units of pressure and permeability for the above equation are MPa and m^2, not bars and nanodarcies as shown in Fig. 2.)

To illustrate the influence of the pressure-dependence of permeability on reservoir water loss, the Darcy flow equation in its steady-state form was used for ease of computation and clarity of comparison

$$\dot{Q} = \bar{k}\,\frac{A}{\mu}\,\frac{\Delta P}{\Delta L} \quad (6)$$

where $\bar{k}$ is the mean permeability over the pressure range, A is the reservoir perimeter area (about 2×10^6 m^2), μ is viscosity, and $\Delta P/\Delta L$ is the overall pressure gradient at the boundary of the reservoir.

Reasonable estimates for the mean peripheral reservoir permeability, for a range of HDR reservoir pressure levels, can be obtained from Eq. 5 by using the integral mean value theorem from calculus

$$\bar{k} = \int_{P_2}^{P_1} k(P)dp/(P_1-P_2)$$

where P_1 and P_2 define the range of the effective stress variation at the boundary of the reservoir region. That is,

$$P_1 = \sigma_2$$

$$P_2 = \sigma_2 - P_r$$

where σ_2 is the far-field effective earth stress parallel to the strike of the reservoir region (and therefore normal to the permeating microcrack network off the "sides" of the reservoir), and P_r is the specified HDR reservoir pressure above hydrostatic. For the region surrounding the Phase II reservoir, σ_2 is assumed to be about 35 MPa above hydrostatic pressure based on several indirect measurements.

Figure 3 shows the calculated variation in reservoir water loss ($\dot{Q}$ in Eq. 6) as a function of reservoir pressure, normalized to the water loss for a pressure of 24 MPa -- the mean reservoir pressure level for Experiment 2074 as discussed in the next section. It is significant to note at this point that the predicted water loss at the higher reservoir pressure maintained for the last two weeks of the ICFT (31 MPa) is less than twice that for Experiment 2074 (at 24 MPa), as compared to the measured increase of over a factor of 4 (to 5 l/s during the last 6 days of the ICFT).

Measured Water Losses for the Phase II Reservoir

Since completing the engineering of the Phase II reservoir in 1985, two significant flow tests have been conducted: the 30-day ICFT in mid 1986, and the 7-day flow test in December of 1987 called Experiment 2074.

1. Experiment 2074. The damaged Phase II reservoir production wellbore EE-2 at the Fenton Hill Hot Dry Rock site was sidetracked and redrilled in October and November of 1987, resulting in the new wellbore, EE-2A. A 7-day flow test was conducted to determine the post-drilling condition of EE-2A; the proper depth for a cemented liner to be installed in the open hole; the effect of redrilling on the Phase II reservoir flow paths; production temperatures, impedance and water loss; and to assess the need for reservoir stimulation through this new wellbore.

Figure 4 shows both the injection flow rate and the measured water loss during this brief flow test. As shown, the water loss after only 7 days had declined to 1.4 l/s (22.5 gpm), and was still decreasing at a rate of about 0.13 l/s/day (2 gpm/day). By extrapolating the decline trend shown in Fig. 4, it appears probable that the reservoir water loss would have further declined to no more than 1.2 l/s (19 gpm) in 3 more days (10 days total).

During the last 3 days of Experiment 2074, the reservoir injection pressure was held constant at about 24 MPa (3480 psi) by slowly reducing the injection flow rate as shown in Fig. 4. Therefore, by using the above extrapolated water loss rate of 1.2 l/s at 24 MPa, one is able to apply a reasonable calibration factor to the normalized reservoir water loss rate curve shown in Fig. 3.

It should be noted that Experiment 2074 was essentially an aseismic flow test, with no events large enough to be located. However, numerous very small microseismic events were detected at the close-in geophone located at a depth of 2865 m in a nearby borehole. These very small events were particularly numerous during the last two to three days of pumping. Unfortunately, the absence of significant seismic activity during this flow test may be interpreted in two different ways: either the reservoir was not fully inflated after only 7 days of injection or, a pressure of 24 MPa is not sufficient to extend the reservoir by additional shear slippage on the peripheral joints. This flow test was just not long enough to differentiate between these two different hypotheses.

2. The Initial Closed-Loop Flow Test (ICFT). The 30-day ICFT (Dash et al., 1988) was essentially performed in two equal segments: an initial 15-day segment at an average injection rate of 11.5 l/s, and a final 15-day segment at an average injection rate of 17.8 l/s. During the first segment, the injection pressure stabilized at a level of about 27 MPa

(3900 psi) in 13 days, and during the second segment the injection pressure again stabilized at about 31 MPa (4500 psi) after an additional 12 days.*

Figure 5 shows both the injection pressure and water loss rate profiles during the ICFT. The water loss after 14 days (on 3 June) was 2.3 l/s (37 gpm) at a pressure of 27 MPa, and after 12 more days (on 14 June) was about 5 l/s (79 gpm) at a pressure of 31 MPa. As pointed out by Dash et al. (1988), the water loss near the end of the ICFT was excessive, and since it was accompanied by a significant amount of microseismic activity, suggested active reservoir growth at an injection pressure of 31 MPa. Based on a re-analysis of the relevant ICFT data, we further note that the Phase II reservoir was also actively growing at an injection pressure of only 27 MPa during the latter part of the initial lower-flow-rate segment. Table II compares the measured water losses for the ICFT with those predicted from Fig. 3, using the calibration factor determined from Experiment 2074: a water loss rate of 1.2 l/s at 24 MPa after 10 days. As shown in Table II, the ICFT water loss values do appear to be excessive, even at the lower 27 MPa pressure level.

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* Note: After the reservoir has been reinflated, the pressure near the boundaries of the reservoir is assumed to be approximately equal to the injection pressure.

Table II
Comparison of the Measured and Predicted Water Loss During the ICFT

	First Segment	Second Segment
Date:	2 May	14 May
Injection Pressure, MPa (taken as the reservoir pressure)	27	31
Water loss rate, l/s	2.3	5.0
Ratio of water loss to that at 24 MPa (Experiment 2074):		
Observed, ICFT	1.9	4.2
Predicted, Fig. 3	1.3	1.9

Microseismic Activity During the ICFT

As noted previously, the Phase II reservoir was essentially aseismic during the 7-day Experiment 2074 flow test. In contrast, the reservoir was quite seismically active during the ICFT, even during the initial, lower-flow-rate segment. This activity is shown in Fig. 6, a plot of the cumulative number of locatable microseismic events during the ICFT. (Also shown in Fig. 6 is the injection pressure profile for correlation purposes.)

Through 4 June during the first (lower) flow rate segment, 41 microseismic events were recorded which were sufficiently large to be adequately received at all three downhole stations and therefore reliably located. Figures 7 and 8 are plan and section views showing the locations of these 41 events superimposed on maps of the microseismic event locations defining the previous Phase II reservoir region, as initially formed during the Massive Hydraulic Fracturing Test in December 1983, and extended in mid-1985 during the high-pressure injection of Experiment 2062. Even at an injection pressure of only 27 MPa, it is readily apparent from these two figures that the reservoir was expanding: generally to the east as shown in Fig. 8, and in two discrete regions as shown in the epicenter plot (Fig. 7). The obvious conclusion is that an injection pressure of 27 MPa (3900 psi) is <u>above</u> the threshold pressure for active reservoir extension.

When the surface injection pressure was increased to over 30 MPa on the afternoon of June 4 by increasing the pumping rate to 18 l/s (6.8 BPM), there was a resulting "burst" of microseismicity lasting for the next 37 hours (Fig. 6). The onset of this period of very active reservoir seismicity is coincident with a sudden and pronounced 7.9 l/s increase in the reservoir water loss rate as shown in Fig. 5 (from 2.3 l/s to 10.2 l/s). Again, it is clear that the reservoir was expanding -- and even more vigorously -- at this higher injection pressure. The subsequent peak in seismic activity on June 12 appears to represent an episodic extension of the Phase II reservoir. This additional period of very rapid reservoir expansion was probably the direct result of the sudden -- but short-lived -- 24% increase in the injection flow rate, from 17.8 to 22 l/s, which was accompanied by the observed pressure "spike" to 33.6 MPa (4870 psi) shown in Fig. 6.

Figures 9 and 10 show composite plan and section views of all the reliably located microseismic events during the entire 30-day ICFT. Again, it can be seen that there was continuing reservoir growth to the east in the general regions first stimulated at 27 MPa (refer to Figs. 7 and 8). However, in composite, there is also considerable downward growth to the south and east, and a pronounced shallower extension to the south -- almost 600 m away from the injection zone shown in Fig. 9 (solid line).

One further point can be made from the seismic data and injection pressure data recorded during the first 9 days of the ICFT. The two early pressure pulses above 30 MPa shown in Fig. 6, lasting for 28 hours on May 25 and 26, and 12 hours on May 27 and 28, produced very different microseismic responses from the reservoir. The first -- and longer -- pulse, resulting from an increase in the injection rate to 18 l/s, was <u>aseismic</u>, in marked contrast to the reservoir behavior during the second flow rate segment. However, the second -- and shorter -- pulse, again resulting from a short period of increased flow, produced 16 microseismic events. That the first pressure pulse above 30 MPa was aseismic, strongly suggests that the reservoir was not yet fully inflated at this time, even after 7 days of pumping. However, the onset of microseismic activity at 04:00 on May 28 (see Fig. 6) appears to mark the point where the reservoir first started to expand. By integrating the water loss profile of Fig. 5 through 04:00 on 28 May (5,520 m^3), and subtracting out an estimate for the far-field permeable flow loss during these 8.5 days (920 m^3), one can infer that it required approximately 4,600 m^3 (1.2×10^6 gal) of water to reinflate the Phase II reservoir to about 27 MPa, the mean injection pressure during the previous 30 hours (assumed to be approximately equal to the reservoir pressure after 8 days of inflation).

In reference to the lower-pressure Experiment 2074, the integral of the water loss profile shown in Fig. 4 is only 1,410 m^3 (372,000 gal), for the 7 days of pumping at 24 MPa. This is only 30% of the ICFT inflation volume of 4,600 m^3 at 27 MPa given above. This implies that the Phase II reservoir was not fully inflated by the end of this 7-day flow test, suggesting that the reservoir could have started to extend after several more weeks of pumping at 24 MPa.

Conclusions

1. The Gangi pressure-dependent permeability model has been proposed for predicting the peripheral water loss from a hydraulically stimulated region of naturally jointed, crystalline rock. This model has been shown to adequately represent the permeability of both jointed and microcracked crystalline rock as a function of effective stress.
2. Above a threshold pressure of less than 27 MPa (3900 psi), the deeper Phase II HDR reservoir at Fenton Hill is shown to expand due to additional joint stimulation at the boundaries of the previously stimulated region.
3. For long-term nonextensional flow testing, the Phase II HDR reservoir should be operated at a surface injection pressure less than 27 MPa (3900 psi), and more probably in the range of 24 MPa (3500 psi).

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