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PRESSURE TESTING OF A HIGH TEMPERATURE NATURALLY FRACTURED RESERVOIR

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ABSTRACT

Los Alamos National Laboratory has conducted a number of pumping and flow-through tests at the Hot Dry Rock (HDR) test site at Fenton Hill, New Mexico. These tests consisted of injecting fresh water at controlled rates up to 12 BPM (32 ℓ/s) and surface pressures up to 7,000 psi (48 MPa) into the HDR formation at depths from 10,000 - 13,180 feet (3050 -4000 m). The formation is a naturally fractured granite at temperatures of about 250°C. The matrix porosity is <1% and permeability is on the order of 1 nD (10^{-21} m^2). Hence most of the injected fluid is believed to move through fractures. There has been no evidence of fracture breakdown phenomena, and hence it is believed that pre-existing joints in the formation are opened by fluid injection. Water losses during pumping are significant, most likely resulting from flow into secondary fractures intersecting the main fluid conducting paths.

The pressure-time response observed in these tests can be interpreted in terms of non-isothermal, fracture-dominated flow. As the fluid pressure increases from small values to those comparable to fracturing pressures, the formation response changes from linear fracture flow to the highly nonlinear situation where fracture lift off occurs. A numerical heat and mass flow model was used to match the observed pressure response. Good matches were obtained for pressure build up and shut-in data by assigning pressure dependent fracture and leak-off permeabilities.

Introduction: The response of a fracture dominated, non-isothermal system to high injection/falloff pressures is strikingly different from conventional petroleum or geothermal reservoirs. Petroleum reservoirs often behave like media with constant porosity and permeability and isothermal flow. In geothermal reservoirs, although the temperature dependence of fluid properties must be accounted for, the formation can still be treated as having constant porosity and permeability. Non-isothermal injection/falloff tests at low pressures have been analyzed for geothermal reservoirs (Bodvarsson, Pruess, and O'Sullivan 1985; Cox and Bodvarsson, 1985; Miller, 1980). Isothermal pressure behavior during hydraulic fracturing treatments (Nolte, 1982; Nolte and Smith, 1981) and in-situ stress measurements (Hickman and Zoback, 1981) has also been discussed.

This behavior is in contrast to the case of hot dry rock (HDR) reservoirs at Fenton Hill, New Mexico, where cold water is injected into a hot rock mass at pressures approaching the earth stresses. The pressure behavior of this reservoir can be explained by considering the fluid flow through a small number of fractures. These fractures are inflated as fluid pressure increases, giving rise to a strongly pressure-dependent aperture and conductivity. As the fluid pressure in the fracture approaches the normal earth stress the fracture lifts off and any further fluid injection results in fracture volume increase, giving rise to a nearly constant wellbore pressure. If the well is shut-in after reaching the constant pressure range, a sudden drop in pressure is observed followed by a more gradual decay, resulting from the leak-off of the fluid stored in the wellbore to the formation through fractures.

The two most important formation parameters determined from pressure tests in the Fenton Hill reservoir are the near wellbore impedance and fracturing pressures. The near wellbore impedance at low pressures can be determined from the square-root time portion of the injection data. In a typical test this occurs during early pumping when the transient thermal effects in the wellbore are important. The pressure fall off from the shut-in data can be used to estimate impedance and leak-off permeabilities at higher pressures. Again thermal transient effects are important. Fracturing pressures are obtained from extrapolating the fracture extension pressures to zero flow rate. Although the fracture extension pressures, in principal, are insensitive to thermal transients, the time required to approach fracturing pressures depends on fracture impedance and temperature-dependent fluid properties. Hence, in practical situations where the pumping times are limited, erroneous results can be obtained unless temperature effects are taken into account.

These considerations have motivated a detailed modeling study of the early time pressure buildup and fall-of data acquired from field tests. In this paper a numerical model of a pressure dependent joint is used for studying its pressure response. The data from a recent pumping test (Expt. 2061) is analyzed, providing a quantitative assessment of the effect of both the pressure-dependent aperture and temperature on reservoir properties.

Description of the Pumping Experiment: Experiment 2061 was carried out by injecting 1.38 million gallons (5.2 million ℓ)of fresh water into the well EE-3A at depths between 12,555' (3827 m) and 13,180' (4017 m). A "thief" zone accepts water at pressures significantly lower than those encountered in the tests, and hence the test interval was isolated using an inflatable packer (Dreesen et al, 1986). The injection rates ranged from 1 bpm (2.7 ℓ/s) to 12 bpm (32 ℓ/s). Water was also injected down the annulus into the thief zone to improve packer performance by lowering the pressure differential across the element. Pre-test and post-test temperature logs were used to identify the fluid outlets. Most of the fluid exited at 13,180' with minor flow exits through 6 other fractures.

The pressure vs time response of the system early in the test is shown by the solid line in Figure 1. This is the data used for history matching. At very early times the response is linear, indicating wellbore storage. At a pressure of about 800 psi (5.5 MPa), the curve deviates from the straight line and pressure increases at a slower rate, indicating flow out of the wellbore into a system with increasingly lower flow impedance. At about 4200 psi (29 MPa), further pumping produced practically no change in the pressure. The pumping was stopped after 45 min., resulting in a sudden drop of 145 psi (1 MPa), followed by a gradual decay.

Description of the Model: Calculations were performed using the 3-D finite element reservoir simulator FEHM (Zyvoloski, 1983). The reservoir was modeled in radial geometry as a wellbore intersecting a horizontal penny shaped fracture with radial flow bounded by a permeable strata. Heat and mass transfer was allowed between the fracture, the wellbore and these strata. The element grid is shown in Figure 2. All of the boundaries are "no flow." Also shown in the figure is a fracture near bottomhole representing the main fluid outlet, as well as an upper zone fracture connected only to the annulus. This upper zone fracture represents the low pressure thief zone, isolated from the test interval by the packer. Fluid flow through the fracture was modeled using the parallel plate law.

$$k = w^2/12 \qquad (1)$$

where k is the permeability, factor, and w is the aperture. The fracture aperture, w, was related to the local pressure using an empirical equation (Zyvoloski, 1985) given by

$$w = w_o \exp (B\Delta P) \qquad (2)$$

where w_o and B are constants determined such that w_o equals some predetermined value (see Eq. 3) at a fracturing pressure ΔP_f. The form of the aperture law was motivated by the work of Barton et. al. (Barton, 1984), whose data suggest an exponential rise in fracture conductivity with pressure. The exponential relation provides "pressure regulation" by allowing the aperture to open to large values once the pressure reaches a predetermined extension condition. The effect is illustrated in Figure 3, which shows the relationships of aperture and joint permeability with pressure. Since the pumping test is short, the pressure affects only a small region around the wellbore. Thus the formula of Geertsma and de Klerk (Geertsma, 1969) for maximum aperture is used:

$$w_{max} = 2\ (\mu Q\ R/G)^{.25} = w_o \exp (B\ \Delta P_f) \qquad (3)$$

where μ is the viscosity, Q is the flow rate, R is the fracture radius, and G is the rock shear modulus. Using values appropriate to Fenton Hill and Experiment 2061 (Q = .00265 m^3/S, R = 5 m, G = 2.65 x 10^{10} Pa), we obtain a maximum aperture of 0.0002 m. In addition to the pressure dependence of the joints, it was also necessary to assume pressure dependent leak-off permeabilities in order to match shut-in data.

Results and Discussion: Figure 1 shows the computer model results of the simulation of Exp. 2061, along with the experimental data. The match is very good for both the build up and shut-in. The parameters used to fit the experimental data are shown in Table I. In obtaining the match several interesting facts were uncovered. First, it was impossible to match the sharp leveling off of pressure while pumping without a pressure-dependent aperture. Second, it was necessary to assume pressure-dependent permeabilities orthogonal to the main fracture. Without this assumption, the pressure dropped much faster than the experimental results, as shown in Figure 4. It was also encouraging to note that the same aperture law was needed for both the build-up and shut-in modeling. This means, in contrast to the commonly held belief, that at least for the low pressure pumping in the new Phase II reservoir at Fenton Hill, it is not necessary to invoke "self propping" in order to explain the observed "soft" shut-in behavior.

Also shown in Figure 1 are the calculated pressures for the case of isothermal flow using the same parameters as those in Table I. Figure 5 shows a match obtained for the isothermal case by adjusting the formation parameters. The parameters needed for the match are given in Table II. Note that the match is not as good as that for the temparature-dependent simulation. While it was not necessary to change the aperture law the maximum permeabilities in the x and y directions were larger by almost an order of magnitude. The discrepency is due to the difference in viscosities of the surface and bottomhole fluids. Thus we have a result similar to that observed for non-isothermal pressure testing in homogeneous reservoirs. The apparent fracture extension pressure for the isothermal case is 10 percent higher than that for the non-isothermal case. Also the slope of the shut-in curve indicates a lower apparent fracture impedance for the non-isothermal case. Future work will be focused on further quantifying these effects and extending them to longer duration tests. The parameters obtained from these simulations will then be used for estimating longterm reservoir behavior.

CONCLUSION

1. The assumption of a pressure dependent aperture law in a reservoir simulator is an effective way to model pressure build-up tests in fractured reservoirs.

2. Pressure dependence of leak-off permeability was necessary to explain shut-in data in a recent Fenton Hill pumping test.

3. Apparent impedance values and ISIP pressures were lower for the non-isothermal analysis than for the isothermal case.

4. Pressure-dependent apertures are necessary to describe pressure behavior of the Fenton Hill reservoir. Simulations indicate that temperature dependent properties must be accounted for.

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Table I

Parameters for Non-Isothermal Model

Parameter		Value
Permeability	r-direction	$10^{-15}m^2$ (max)
	y-direction	$10^{-18}m^2$ (max)
	joint	$10^{-10}m^2$ (max)
Porosity	Matrix	.01
	fracture	1.0
Rock Density		$2500kg/m^3$
Rock Specific Heat		1000J/kg°C
Joint Radius		300m (maximum)
		5m (nominal)
Fracture Width		.0002m (maximum)
Initial Pressure		0.MPa
Initial Temperature	0<y<750m	12.35 -.0956y °C
	750<y<4100m	72.29 + 0.00996y +$0.0000105y^2$
Injection rate	0<time<46 min	1BPM(2.65 l/s)
	46<time<56min	0.0
w_o		.001
B		32.7

Table II

Parameters for Isothermal Model

Parameter		Value
Permeability	r-direction	$5x10^{-15}m^2$ (max)
	y-direction	$5x10^{-18}m^2$ (max)
	joint	$10^{-10}m^2$ (max)
Porosity	Matrix	.01
	fracture	1.0
Rock Density		$2500kg/m^3$
Rock Specific Heat		1000J/kg°C
Joint Radius		300m (maximum)
		5m (nominal)
Fracture Width		.0002m (maximum)
Initial Pressure		0.MPa
Initial Temperature		12.35°C
Injection Rate	0<time<46 min	1BPM(2.65 l/s)
	46<time<56min	0.0
w_o		.001
B		32.7

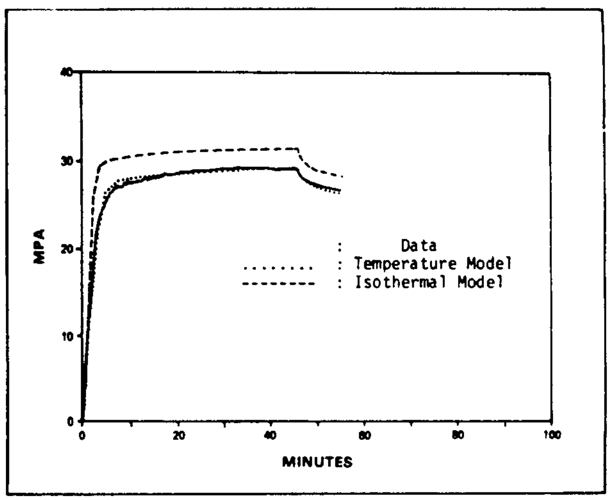

Figure 1. Observed and Model Pressure Response, Expt 2061

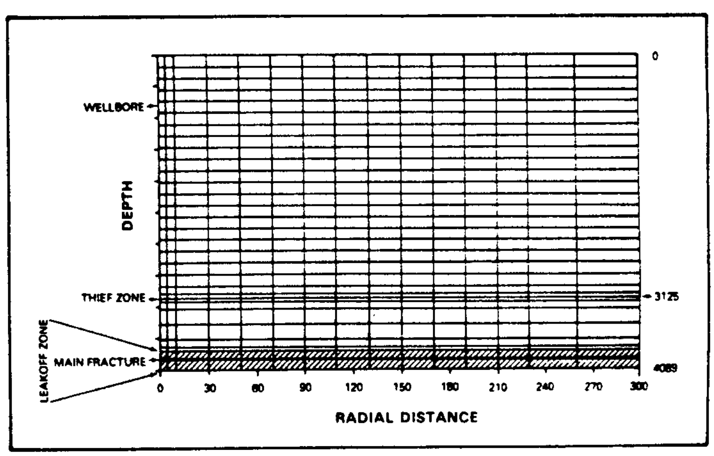

Figure 2. Schematics of the Model and Numerical Grid

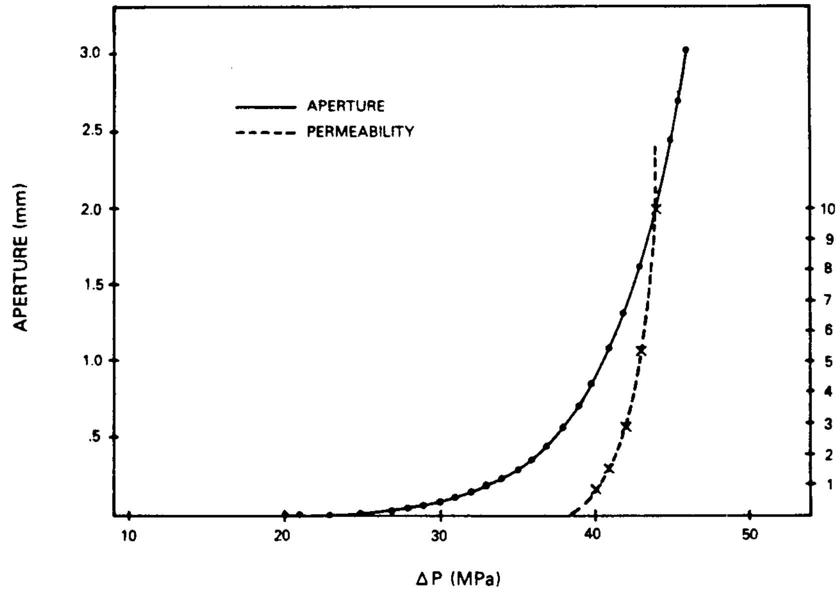

Figure 3. Fracture Apperture and Permeability vs. Pressure Used For Modeling

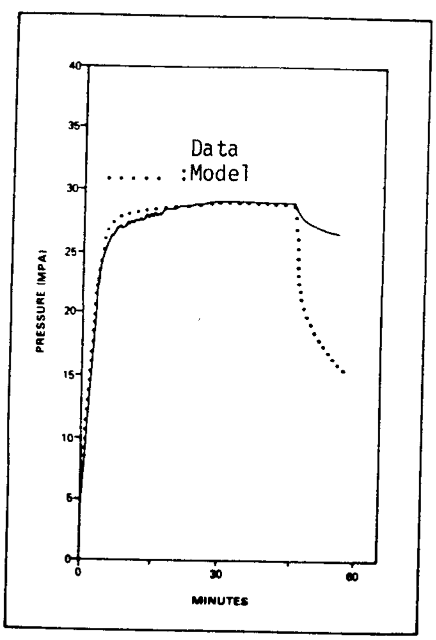

Figure 4. Model Results Using Constant Leakoff Permeability, Compared With Experimental Data.

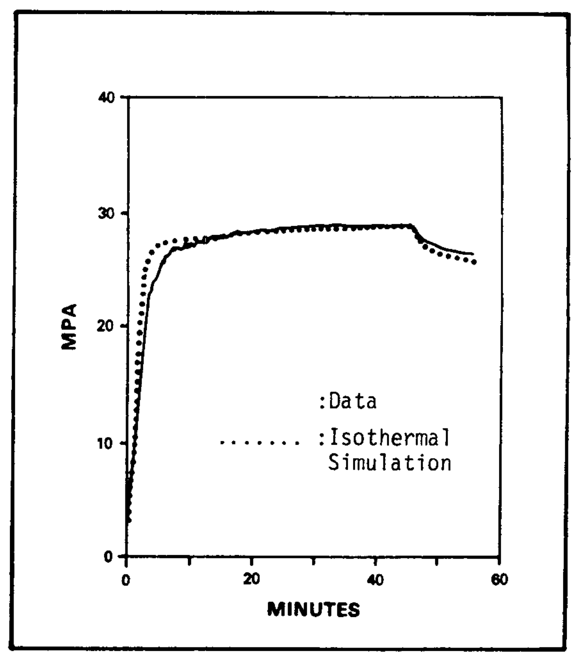

Figure 5. Isothermal Simulation of the Experimental data Using Values From Tabel 2.