Proceedings Seventh Workshop Geothermal Reservoir Engineering
Stanford, December 1981. SGP-TR-55.

ANALYSIS OF WELL DATA FROM THE KRAFLA GEOTHERMAL FIELD IN ICELAND

G.S. Bodvarsson†, S. Benson†, O. Sigurdsson§
G.K. Halldorsson§, and V. Stefansson§

†Earth Sciences Division, Lawrence Berkeley Laboratory, Berkeley, California 94720
§National Energy Authority, Reykjavik, Iceland

Introduction As part of an informal agreement between Lawrence Berkeley Laboratory (LBL) and four Icelandic Institutions responsible for the exploration and development of geothermal energy in Iceland, well data from the Krafla geothermal field in Iceland have been analysed. The data consist of injection test data and production data. The injection test data were analyzed for the reservoir transmissivity and storativity. Analysis of the production data to determine the relative permeability parameters for the Krafla field is in progress. In this paper, the analysis of injection tests at the Krafla field will be described.

The Krafla geothermal field is located on the neovolcanic zone in north-eastern Iceland (Figure 1). The neovolcanic zone is characterized by fissure swarms and central volcanoes. The Krafla geothermal field is located in a caldera (8 x 10 km), with a large central volcano, also named Krafla.

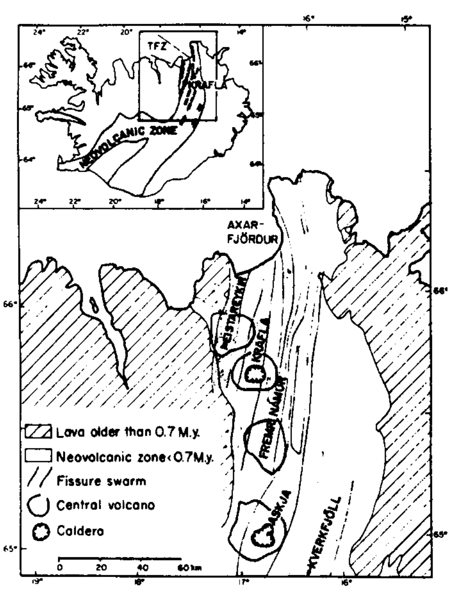

Figure 1 The location of the Krafla geothermal field in Iceland.

Surface geophysical exploration at Krafla was initiated in 1970. In 1974, two exploration wells were drilled, and the subsurface data indicated the presence of a high temperature (>300°C) geothermal field. Presently, 18 wells have been drilled at Krafla: the locations of the wells are shown in Figure 2.

Stefansson (1981) has presented a detailed description of the reservoir system at Krafla; his model is summarized below. In the old well field (wells 1-13, & 15) pressure and temperature data from the wells have indicated the presence of two reservoirs. The upper reservoir contains single phase liquid water at a mean temperature of 205°C. This reservoir extends from a depth of 200 m to a depth of about 1100 m. The deeper reservoir is two-phase, with temperatures and pressures following the saturation curve with depth. This reservoir directly underlies a thin confining layer at a depth of 1100-1300 m and it extends to depths greater than 2200 m (the depth of the deepest well). The two reservoirs seem to be connected near the gully, Hveragil. In the new well field (south of Mt. Krafla, wells 14, 16-18), the upper reservoir has not been identified, and only the twc-phase liquid dominated reservoir seems to be present.

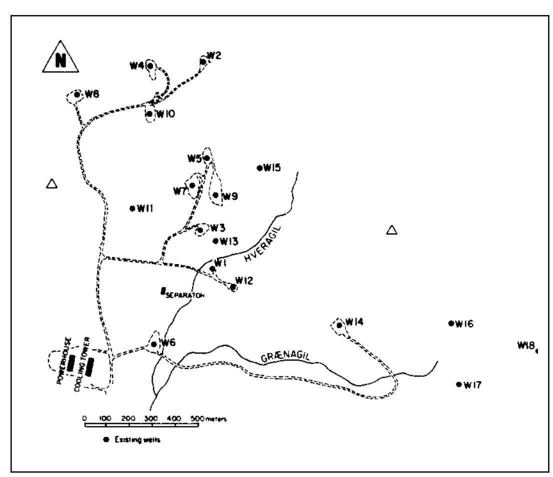

Figure 2 Well locations.

Well testing at Krafla A common procedure at Krafla is to perform an injection test soon after the drilling is completed. This procedure has been applied to the last 13 wells drilled at Krafla (wells 6–18). The purpose of the injection tests is twofold: 1) to attempt to stimulate the well, i.e., increase the water losses, and 2) to obtain data that can be analyzed to yield the transmissivity of the formation.

Experience obtained from injection testing of wells in Krafla, as well as in several other geothermal fields in Iceland, has shown that in many cases apparently dry wells (small water losses) have been sufficiently stimulated to become reasonably good producers. The reasons for this are not presently known, but several possible explanations are: 1) cleaning of fractures, 2) opening up of fractures due to increases in pore fluid pressure, or 3) thermal cracking close to the well, due to the temperature difference between the injected water and the hot reservoir water.

Conventional type curve analysis of the injection test data from Krafla has been reported by Sigurdsson and Stefansson (1977) and Sigurdsson (1978). In the present study the use of numerical simulators for well test analysis is illustrated.

Analysis of Injection Test Data The well KG–13 (W13) at Krafla was drilled in June–July 1980 (Figure 2). A simplified casing diagram for the well is shown in Figure 3. The well is cased (9 5/8 in casing) to a depth of 1021 m, below that a 7 5/8 in slotted liner extends to the well bottom. Thus the well is completed only in the lower, two-phase reservoir. The figure also shows the location of a major fracture feeding the well at a depth of 1600–1700 m.

A few days after drilling, two injection tests were performed (10th and 11th of July, 1980, respectively). During the tests a pressure transducer was located at a depth of approximately 220 m below ground surface, and continuous readings were obtained at the surface. The temperature of the injected water was approximately 20°C.

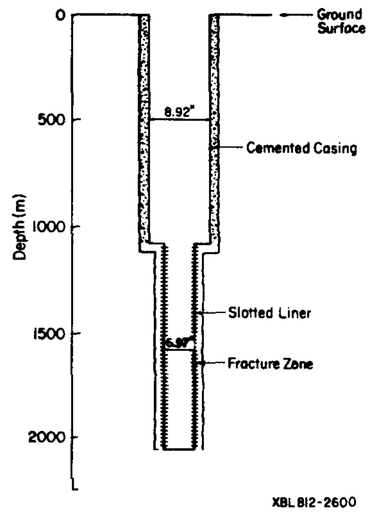

Figure 3 Simplified casing diagram for well KG–13.

The injection rates at the surface are shown in Figure 4 along with the water level data for the second test. After the first injection test was completed (July 10th), injection was continued throughout the night at a stable injection rate of approximately 29 kg/s until initiation of the second test (see Figure 4). The second injection test consisted of an initial falloff, followed by three injection segments with increasing flow rates, and finally, a second falloff. During the test, a free surface water table was Present in the well, and since the injection tests are short, significant wellbore storage effects were present. Furthermore, analysis of the injection test was possibly complicated by thermal effects, as 20°C temperature water was injected into a two–phase reservoir of

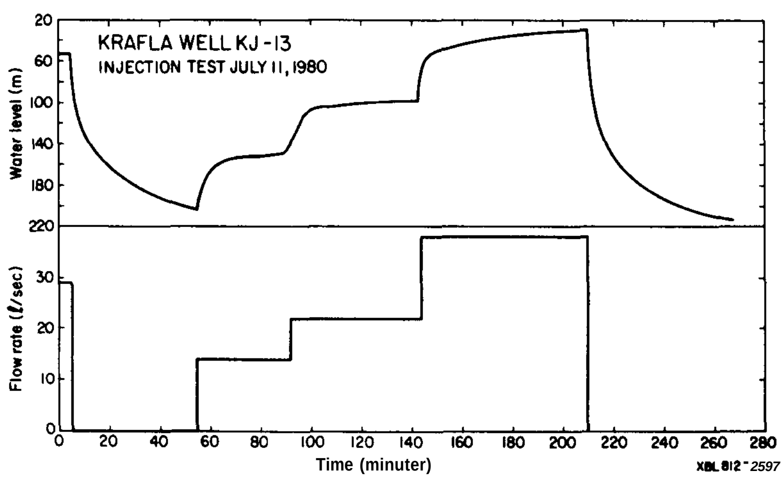

Figure 4. Flow rate and water–level data for injection test of well KG–13.

much higher temperature. For the present analysis, the fracture zone at 1600–1700 m depth was assumed to be the primary aquifer; the thermodynamic conditions at this depth correspond to a temperature of approximately 320°C.

The first step in the analysis of this well test was to correct for the wellbore storage effects. They were easily accounted for by using variable flow rate analysis, rather than the constant step-rate surface flow rates shown in Figure 4. Since the well head flow rate and the water level in the well were known, the sandface flow rate could be calculated on basis of simple mass balance as follows:

$$q_s = q_w - \pi r_w^2 \rho_w \Delta s \qquad (1)$$

where As denotes the change in the water level. Equation (1) simply states that the water entering the well (q_w) must leave the well (q_s) or be contained in the well, causing a change in the water level (As). Certainly after some time a steady state condition will be reached where the flow rates at the wellhead and at the sandface are identical and consequently the water level is stable (As = 0). However, for the Krafla wells (casing diameter 9 5/8 in), the wellbore storage effects will last for approximately one and one half hours, and therefore the variable flow rate approach must be employed in the test analysis.

Because of the two-phase nature of the Krafla reservoir and the non-isothermal effects introduced by the cold water injection, attempts were made to model the injection test data using the two-phase simulator SHAFT79 (Pruess and Schroeder, 1980) and the non-isothermal simulator PT (Bodvarsson, 1981). However, these attempts were unsuccessful, as a reasonable match with the water level data for entire test (the initial falloff, the three injection steps, and the second falloff) could not be obtained. Further attempts to simulate the injection test data were made using the variable flow rate Theis type model ANALYZE (McEdwards and Benson, 1981) and the numerical simulator PT in its isothermal mode. The best match obtained is shown in Figure 5.

The match is very good at all times, except for the third injection step, where the calculated water level values are slightly higher than the observed values. Figure 5 also shows the calculated sandface flow rates used in the simulation, as well as the well head flow rates.

The parameters obtained from the match were $kH/\mu = 1.52\text{x}10^{-8} m^3/pa \cdot sec$ and $\phi\beta_t H = 8\text{x}10^{-7} m/pa$.

The transmissivity (kH) of the reservoir could not be determined, as it was not obvious if the viscosity (μ) of the cold injection water or the hot reservoir water should be used in the analysis. Furthermore, the total compressibility (β_t) could not be explicitly calculated, as the porosity (ϕ) and the effective reservoir thickness (H) were not known. Further discussion of the reservoir parameters determined from the injection test is given later in this section.

Now let us examine the apparent isothermal behavior observed in the injection test data. Since the fluid viscosity changes by more than an order of magnitude for the temperature range 20° to 320°C, one would not expect isothermal pressure behavior in the data especially when the data is taken during both injection and falloff periods. The reason for this is that for a Theis-type reservoir, the pressure changes during injection will correspond to the cold water fluid properties,

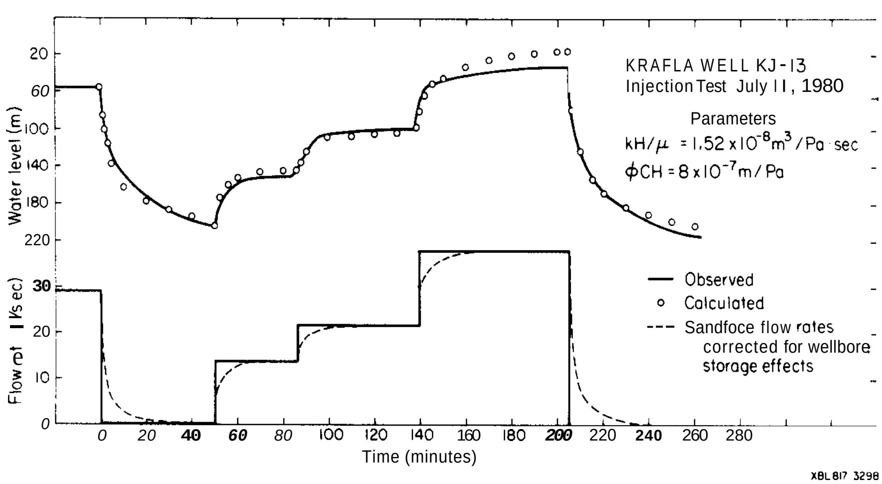

Figure 5. Comparison between observed and calculated water levels for injection test of well KG-13.

whereas during the falloff period, the pressure changes will correspond to the fluid properties of the hot reservoir (Bodvarsson and Tsang, 1980).

In an attempt to explain the isothermal behavior of the data from the injection test, two possibilities must be explored: 1) that the undisturbed reservoir conditions (e.g., T = 320°C) control the pressure response at the well; and 2) that the temperature of the injected water is the controlling factor. As cold water has been injected into the well at all times during drilling (approximately 45 days) and also during the few days after drilling, there must be a cold water zone around the well. Consequently, the first possibility seems unlikely. If the cold water zone around the well is to explain the isothermal behavior in the data, this zone must extend further from the well than the pressure disturbance during each injection step.

In order to study the advancement of the cold-water front along a fracture intercepting the well, the theory developed by Bodvarsson and Tsang (1981) was used. A single horizontal fracture, representing a permeable layer between lava beds, is assumed to absorb the total injection rate. Heat conduction from the rocks above and below the fracture retards the advancement of the cold water front. The equation governing the advancement of the cold water front along the fracture away from the well is:

$$r = \left(\frac{t \cdot q^2 \cdot (\rho_w c_w)^2}{4.396 \cdot \pi \cdot \lambda \cdot \rho_r c_r} \right)^{1/4} \qquad (2)$$

where r is the radial distance of the cold water front away from the injection well, q is the injection rate, λ is the thermal conductivity, and $\rho_w c_w$ and $\rho_r c_r$ are the volumetric heat capacities of the injected water and the rock matrix respectively. Figure 6 shows the advancement of the cold water front along the fracture versus time. The parameters used in the calculations are shown in Figure 6; they represent the average injection rate prior to the injection test, and average thermal properties for basaltic rocks. Figure 6 shows that, if one considers only the injection after drilling (2-3 days), the cold water front will have advanced approximately 50 m away from the well when the second injection test begins. It is of interest to note that this estimate is independent of the fracture aperature (Bodvarsson and Tsang, 1981).

In comparison, the radius of influence for the pressure disturbance due to a typical injection step can be calculated directly from the reservoir diffusivity as follows:

$$r = \sqrt{\frac{4kt}{\phi \mu \beta_t}} \qquad (3)$$

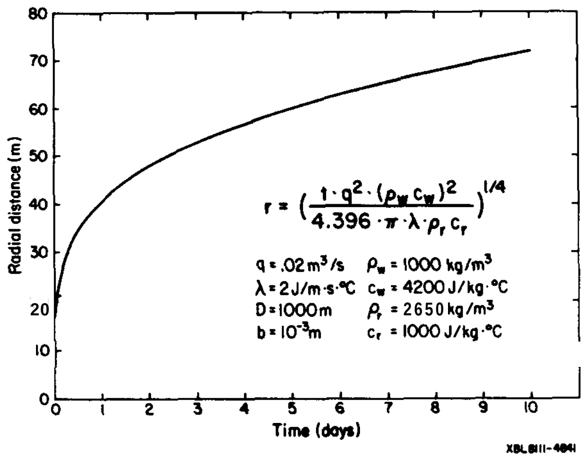

Figure 6 Advancement of the cold water front with time along a horizontal fracture.

Multiplying the numerator and the denominator by the effective thickness of the fracture zone H, the parameter groups determined from the well test (see equations 2 and 3) can be used to determine the radius of influence. For an injection step lasting 1 hour, a radius of influence of 16.5 m can be calculated. As this value (16.5 m) is less than the calculated radial extent of the cold water zone (~ 50 m), isothermal pressure behavior can be expected. If this analysis is correct, the fluid parameters corresponding to the cold injection water should be used, and consequently this implies a transmissivity of kH = 15 Darcy-meters.

The fracture zone (aquifer) feeding the Krafla well KG-13 is believed to be very thin, or on the order of 1 m (Stefansson, personal communication, 1981). If one assumes a value for the porosity (ϕ) for this zone, say $\phi = .10$, a very high total compressibility, $\beta_t = 8 \times 10^{-6}$ pa^{-1} can be calculated using equation (3). This high total compressibility can be explained by the two-phase conditions in the reservoir, or by high fracture compressibility. Due to the uncertainity in explaining the isothermal behavior of the test, both possibilities will be explored.

The compressibility of two-phase fluids is two to four orders of magnitude larger than those of single phase liquid or steam water (Grant and Sorey, 1979). The two-phase compressibility depends on many parameters, such as the temperature, saturation, porosity, and the relative permeability curves. Figure 7 shows the relationship between fluid compressibility and vapor saturation for various values of porosity. In calculating the curves shown in Figure 7 a reservoir temperature of 300°C and the Corey relative permeability curves are used. Comparison of the total compressibility β_t (previously determined $\beta_t = 8 \times 10^{-6}$ pa^{-1}) to Figure 7 yields a porosity value of $\phi \simeq .05$ and vapor saturation of $S_v < .20$. These values agree very well with values of porosity

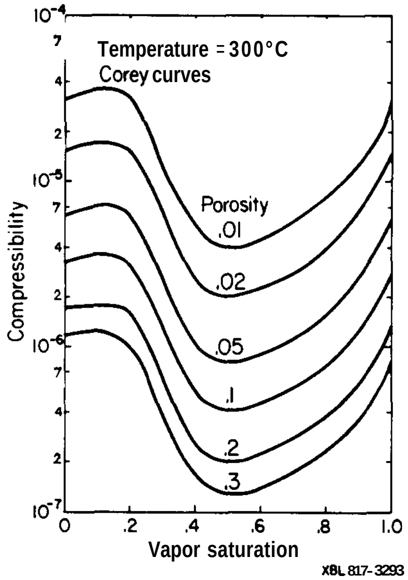

Figure 7 Fluid compressibility as a function of vapor saturation for various values of porosity.

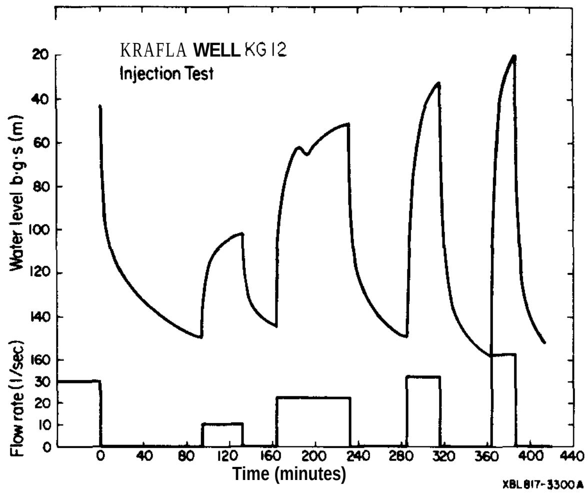

Figure 8 Injection test data for KG-12.

and vapor saturation inferred from other field data (Stefansson, 1981). However, it is rather doubtful that the high compressibility determined from the injection tests is due to the presence of two-phase fluids, because of the cold water zone surrounding the well. It is possible that the high compressibility is due to deformable fractures. In that case, the increase in well losses during injection tests may be due to opening up of fractures caused by increased pore pressures.

The second injection test that was analyzed was performed on well KG-12 (W12). The well is cased (9 5/8 in casing) to a depth of 952 m, and below that to the bottom of the well (2222 m), a 7 in slotted liner is in place. This well is also completed in the lower two-phase reservoir. The major fracture zone is located at a depth of 1600 m, but some contribution to the production from the well may come from fractures located at a depth of 1000 m.

The injection test data, consisting of water level data and wellhead flow rates are given in Figure 8. As the figure shows, for several days prior to the test, cold water at a rate of 30 l/s was injected into the well. After an initial falloff lasting for approximately one and one half hours, four injection/falloff segments with increasing injection rates were used. On the average, each of the injection steps only lasted 40 minutes, so that wellbore storage effects are quite important.

Analysis of the injection test of well KG-12 was carried out using the simulator PT in its isothermal mode. Figure 9 shows the best match obtained between the observed and the calculated water level values. Figure 9 also shows the variable flow rate used in the simulation (broken line) to account for the wellbore storage effects. As the figure shows, the calculated values compare very well with the observed data. However, the entire test could not be simulated using a constant value for kH/μ. For the initial falloff and the first injection-falloff cycle the data were matched reasonably well using $kH/\mu = 1.2\times10^{-8}\ \frac{m^3}{Pa.s}$; however, approximately 200 minutes after the injection test began, a decrease in the water level was observed, although the injection rate remained constant (Figure 9). This implies a change in the transmissivity of the reservoir. This is verified by the numerical simulation, since if the kH/μ factor is kept constant at $kH/\mu = 1.2\times10^{-8}$ over the entire simulation, the calculated pressure changes will greatly exceed the observed ones. Therefore, in the simulation the transmissivity had to be increased to account for the apparent stimulation due to the cold water

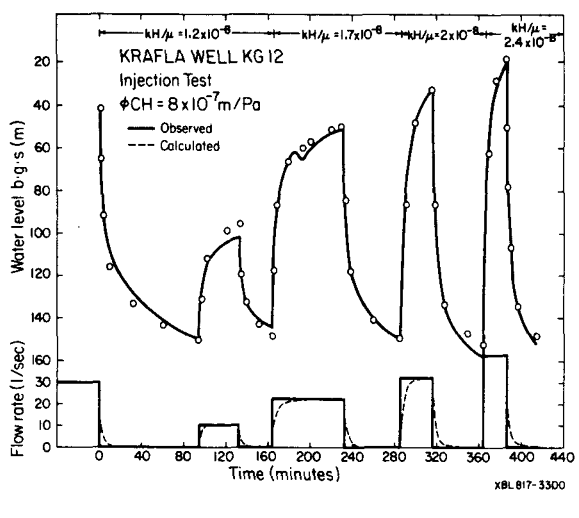

Figure 9 Match of calculated and observed water-level data at KG-12.

injection. In the simulation shown in Figure 9, the kH/μ was increased by a factor of two, from an initial value of $1.2 \times 10^{-8}\ \frac{m^3}{pa \cdot s}$ to a final value of $2.4 \times 10^{-8}\ \frac{m^3}{pa \cdot s}$. Injection test data from several other Krafla wells have shown similar increases in injectivity during injection. The experience at Krafla has indicated that cold water injection can stimulate tight wells into becoming fair producers. Similarily, increases in productivity of flowing wells due to thermal contraction have been reported by Stefansson and Steingrimsson (1980)

In the simulation shown in Figure 9 a constant storativity value was used, $\phi\beta_t H = 8 \times 10^{-7}$ m/pa. This value is identical to the value obtained from the analysis of well KG-13. This indicates either a rather constant distribution of the fluid reserves (ϕ and S_v rather uniform), or a fairly uniform fracture compressibility.

Conclusions Injection test data from the Krafla geothermal field in Iceland have been analyzed using numerical simulation techniques. The results indicate that although the injected water is of a much lower temperature than the undisturbed reservoir water, there are no apparent nonisothermal effects observable in the data. One possible explanation is that a cold water zone exists around the well due to the cold drilling water and that the pressure disturbance during the injection tests does not extend beyond the cold water zone. Thus, the reservoir parameters must be evaluated based on the fluid properties corresponding to the injected fluid.

Numerical modeling studies of injection tests from two of the Krafla wells (KG-12 and KG-13) yielded the transmissivity and storativity of the formation surrounding the wells. The results indicate that the injection test stimulated well KG-12, since an apparent increase in the transmissivity was observed during the test. Also, for both of the wells, the modeling results indicated a high total compressibility. The high compressibility can either be due to the two-phase condition in the reservoir or a high fracture compressibility.

Acknowledgements This research was performed as a part of a cooperative scientific investigation of the Krafla geothermal field between NEA, SEPW, ERI, and SI of Iceland and LBL of U.S.A. This work was supported by the Assistant Sceretary of Conservation and Renewable Energy, Office of Renewable Technology, Division of Geothermal and Hyropower Technologies of the U.S. Department of Energy under Contract No. W-7405-ENG-48.

References

Bodvarsson, G.S. (1981), "Mathematical Modeling of the Behavior of Geothermal Systems under Exploitation", (Ph.D. dissertation) Lawrence Berkeley Laboratory, Berkeley, California.

Bodvarsson, G.S., and Tsang, C.F. (1980), "Thermal Effects in Well Tests of Fractured Reservoirs," Proceedings, Third International Well-Testing Symposium, Lawrence Berkeley Laboratory (March 26-28).

Bodvarsson, G. S., and Tsang, C.F. (1981), "Injection and Thermal Breakthrough in Fractured Geothermal Reservoirs," to be published in the Journal of Geophysical Research, LBL-12698.

Grant, M.A., and Sorey, M.L. (1979), "The Compressibility and Hydraulic Diffusivity of Water-Steam Flows," Water Resources Research, vol. 15, no. 3, p. 684-686.

McEdwards, D.G., and Benson, S.M. (1981), "User's Manual for ANALYZE, Variable-Rate, Multiple-Well, Least Squares Matching Routine for Well-Test Analysis," Lawrence Berkeley Laboratory, Berkeley, California, LBL-10907.

Pruess, K., and Schroeder, R.C., (1980), "SHAFT79 User's Manual," Lawrence Berkeley Laboratory, Berkeley, California, LBL-10861.

Sigurdsson, O., and Stefansson, V. (1977), "Lekt i borholum i Kroflu", (in Icelandic) National Energy Authority of Iceland.

Sigurdsson, O. (1978), "Rennsliseiginleikar efra jardhitakerfisins i Kroflu," (in Icelandic) National Energy Authority of Iceland.

Stefansson, V. (1981), "The Krafla Geothermal Field, Northeast Iceland," Geothermal Systems, L. Ryback and L.J.P. Muffler (editors).

Stefansson, V., and Steingrimsson, B. (1980). "Production characteristics of wells tapping two-phrase reservoirs at Krafla and Namafjall" Proceedings. 6th Workshop Geothermal Reservoir Engineering, Stanford University, Stanford California, SGP-TR-50, 49-59