INJECTION CAPABILITY AT THE RAFT RIVER GEOTHERMAL SITE

U. Ahmed, K. M. Wolgemuth, A. S. Abou-Sayed, A. H. Jones
Terra Tek, Inc., Salt Lake City, Utah

INTRODUCTION

The Raft River Geothermal Resource Area in southern Idaho (Figure 1) is the first location for an electric power plant utilizing a medium temperature ($\approx 145^{\circ}C$) geothermal resource. For the projected 5 MWe pilot geothermal plant, a supply of 2500 gpm of the geothermal fluid is needed. The State of Idaho prefers that the spent brine be reinjected into zones deeper than the known agricultural aquifers. Wells RRGI-6 and 7 (Figure 2) are to be used for injection. The objective of this study is to evaluate the injection capability of the formation.

This paper presents our analysis of several injectivity tests performed by EG&G on RRGI-7 to characterize the injection capability of the formation. The available geological information about the area and preliminary results of a spinner survey[1] have been included in the injectivity test analysis. A wellhead pressure limit of 500 psi has been imposed to prevent injection formation fracturing. Our approach to analysis is to use a two dimensional radial numerical simulator with parameters determined by the test results and from geological data.

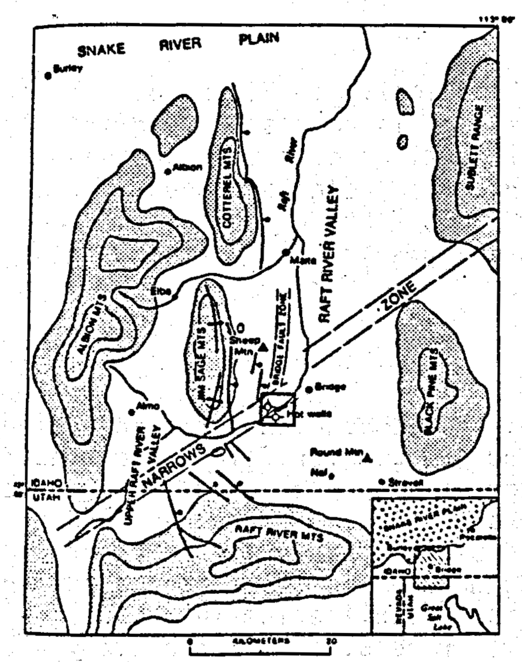

FIGURE 1. Map of the Raft River Valley Area.[6]

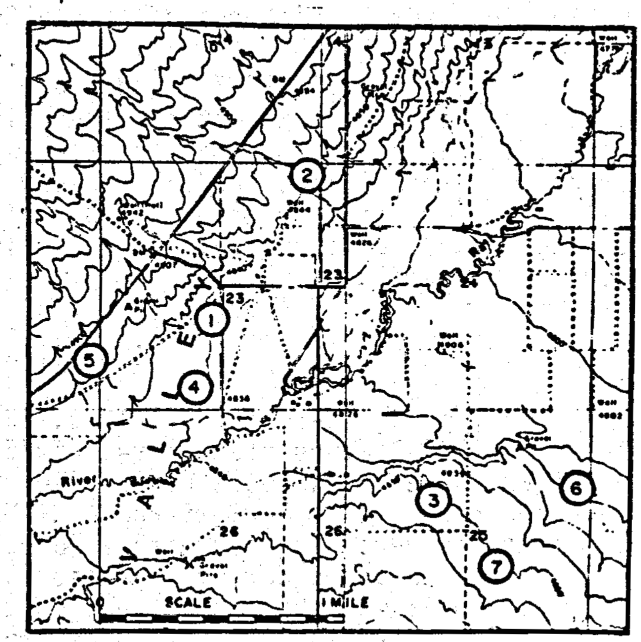

FIGURE 2. Raft River Geothermal Site Well Location (enlarged square section of Figure 1.)

Conventional transient injectivity test analysis assumes that the mobilities of the injected fluid and the *in situ* fluid are the same.[2,3] This condition is not achieved during the injection when the injected fluid and the *in situ* fluid are at considerably different temperatures. However, during the pressure falloff the condition of uniform mobility is more nearly achieved because the fluid is practically isothermal for a considerable distance around the wellbore.[3,4] Therefore, emphasis has been put on interpreting the falloff data.

GEOLOGY

The Raft River Valley is located at the northern edge of the Basin and Range province just south of the Snake River plain (Figure 1). The U. S. Geological Survey has carried out a comprehensive program to elucidate the geology of the valley[5,6,7,8]. It is a north-trending Cenozoic depression bounded on the east, south, and west by mountains. The mountains to the east (Black Pine) and south (Raft River) consist of older Precambrian and Paleozoic metasediments indicative of likely barriers to fluid flow.

Geophysical evidence suggests that along the west side of the valley the Tertiary rocks appear to be separated from the underlying Precambrian basement by a low angle fault, along which the Tertiary rocks have slid off a buried basement dome.[6] It is uncertain whether this will act as a barrier. There is an unconfirmed suggestion that Snake River Plain basalts occur at depth (≈2000 feet) about 30 miles north of the resource and could act as a highly permeable sink.[9] Tuffaceous sediments of Miocene and Pliocene age fill the valley to a total thickness of about 5000 feet.

Injection wells RRGI-6 and 7 are shown schematically in Figure 3. The Salt Lake Formation, target for the reinjected fluid, is composed predominantly of tuffaceous siltstone and sandstone with minor sections of gravel and sand or poorly consolidated sand.[10] Below the casing, both holes are open in the Salt Lake Formation reaching a depth of 3888 and 3858 feet respectively. The casing in RRGI-6 is completed down to 1695 feet whereas in RRGI-7 it extends down to 2044 feet.

INJECTION TESTS

During August-September, 1979, EG&G Idaho, Inc. conducted three injection tests in RRGI-7 at constant rates of 750, 620 and 450 gpm for five and one-half, eight and ninety-six hours respectively. Bottom hole pressure and temperature were recorded with a Hewlett-Packard (HP) probe and wellhead pressures and temperatures were recorded with a Paroscientific Digiquartz system. Measurements were monitored during injection and following shut-in (falloff). Between tests the well was shut-in for enough time to ensure equilibrium in the reservoir. All three injectivity tests provided similar results. For brevity, only the 750 gpm data is discussed in detail here.

<u>750 GPM Falloff Data Analysis:</u> Following five and one-half hours of constant rate injection, the well was shut in and pressure and temperature falloff were

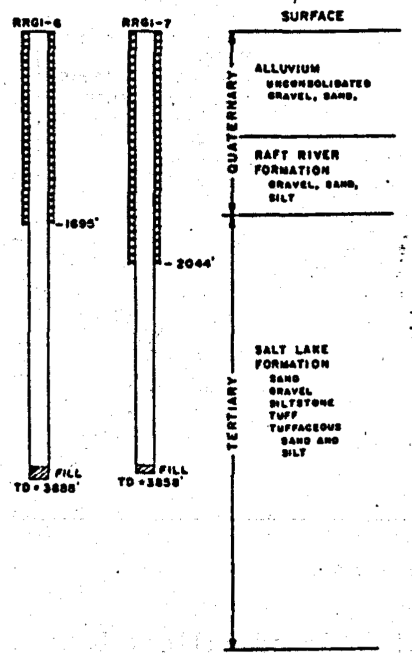

FIGURE 3. Stratigraphy of RRGI-6 and 7.

recorded both bottom hole and at the wellhead. Figure 4 is a log-log plot of the pressure changes versus time for both the bottom hole and wellhead measurements. The wellbore storage effects ceased after about 0.01 hours and the formation compressibility is calculated to be a 1.33×10^{-6} psi^{-1}. Figure 5 is the semi-log plot of pressure and temperature falloff with time as recorded downhole. The bottom hole temperature remained fairly constant at 121°C for about 0.8 hours and good pressure data was collected during that time. From the semi-log straight line the average formation permeability of the open hole was calculated as 37 md and the well had a skin factor of +0.1. When the bottom hole temperature started dropping significantly, the pressure decay rate reduced. At that time, the wellbore was cooling at a much faster rate than the surrounding reserovir and a back pressure on the sandface was created causing a reduction in bottom hole pressure drop. Figure 6 is the semi-log plot of pressure and temperature falloff with time as recorded at the wellhead. The wellhead temperature remained fairly constant at the 127°C for about 0.8 hours and good pressure data up to then was recorded. From the semi-log straight line the average formation permeability of the open hole is calculated as 36. md and the well shows a skin factor of -0.3. When the wellhead temperature started dropping significantly, the pressure decay rate increased because of the thermal contraction of the wellbore fluid.

750 GPM Injectivity Data Analysis: Though the injectivity pressure data was considerably affected by temperature changes (deviation of mobility ratio from unity), it is gratifying to note that upon simple temperature compensation, the injectivity data analysis resulted in similar results to the falloff data analysis. The average permeability is 37 md, total system compressibility is 1.47×10^{-6} psi^{-1}, and the well indicates negligible skin factor (-0.3).

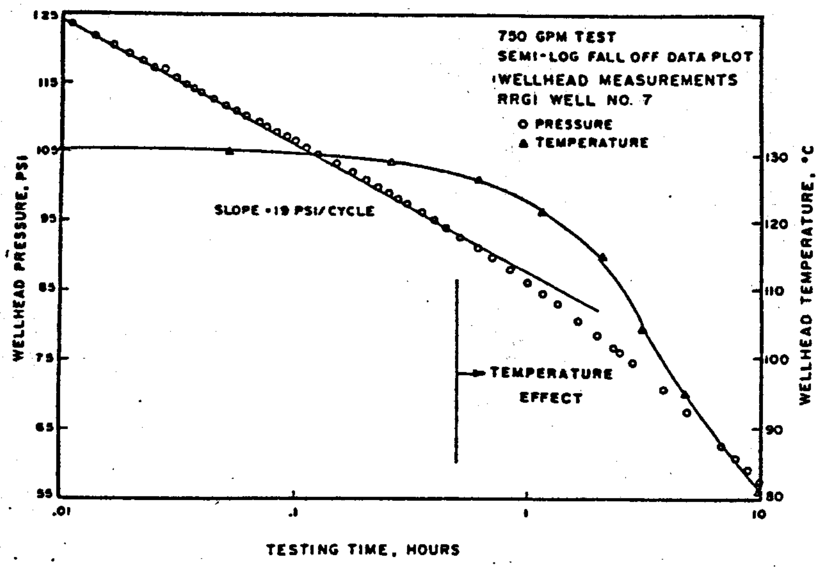

FIGURE 6. 750 GPM Wellhead Falloff Data.

TABLE 1

Well and Reservoir Properties Around RRGI No. 7

Casing Depth	2044 feet
Bottom Hole Depth	3858 feet
Formation Thickness	1814 feet
Average Open Hole Radius	0.58 feet
Formation Porosity	0.2 fraction
Fluid Viscosity	0.285 cp
Initial Reservoir Pressure	1677 psi
Initial Reservoir Temperature	207°F
Wellbore Storage Coefficient	0.00226 res. bbls./psi
Dimensionless Wellbore Storage Coefficient	22.4

TEST	PERMEABILITY md	SKIN FACTOR	TOTAL COMPRESSIBILITY psi^{-1}	RADIUS OF INVESTIGATION ft
750 gpm	36.9	+0.1--0.3	1.4×10^{-6}	1400
620 gpm	35.1	+ .8--0.12	1.55×10^{-6}	1700
450 gpm	37.7	0	1.55×10^{-6}	5800
Analysis Average	36.6 ± 1.3	Negligible	$1.5 \pm 0.1 \times 10^{-6}$	Up to 5800 ft.

Interference with RRGI-6: During the 450 gpm test, the wellhead pressure at RRGI-6 was monitored. Figure 7 is the log-log plot of the wellhead pressure changes versus time. Using an exponential integral solution, the formation capacity between the RRGI-6 and 7 has been calculated to be 2.1×10^5 md-ft. For a formation thickness of 2193 feet (open hole in RRGI-6) the average formation permeability is 96 md. Since this is substantially higher than the 37 md measured around RRGI-7, a zone of high permeability is implied to exist within the vicinity of the two wells.

Similar injectivity and falloff data analysis of the 620 and 450 gpm tests have provided consistent results. The flow properties around RRGI-7 as calculated from the three tests are listed in Table 1, along with the well and fluid properties. Average properties are 36.6 ± 1.3 md permeability, 1.5 ± 0.1 x 10^{-6} psi^{-1} total system compressibility, and negligible (+0.7 to -0.3) skin factor. These reservoir proeprties correspond to a 5800 foot radius of investigation.

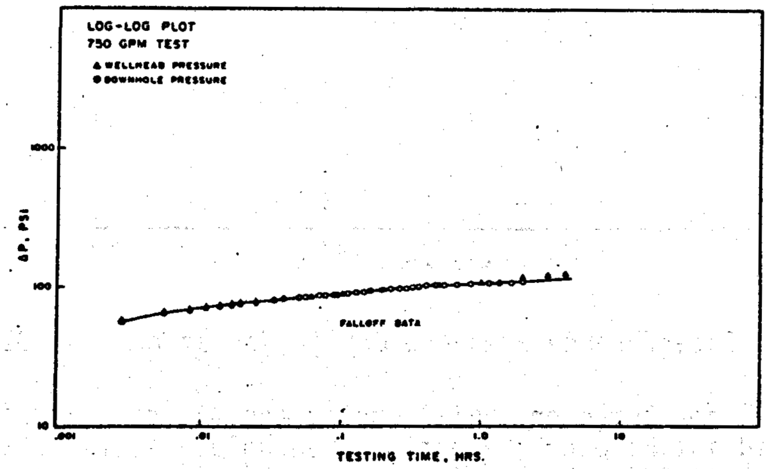

FIGURE 4. Pressure Change Versus Time.
750 GPM Falloff Data.

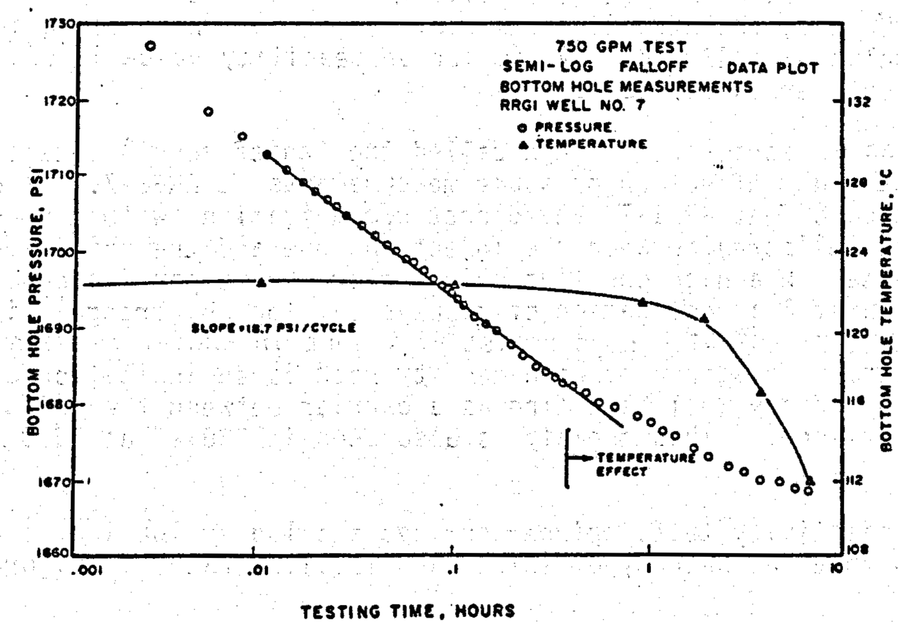

FIGURE 5. 750 GPM Bottom Hole Falloff Data.

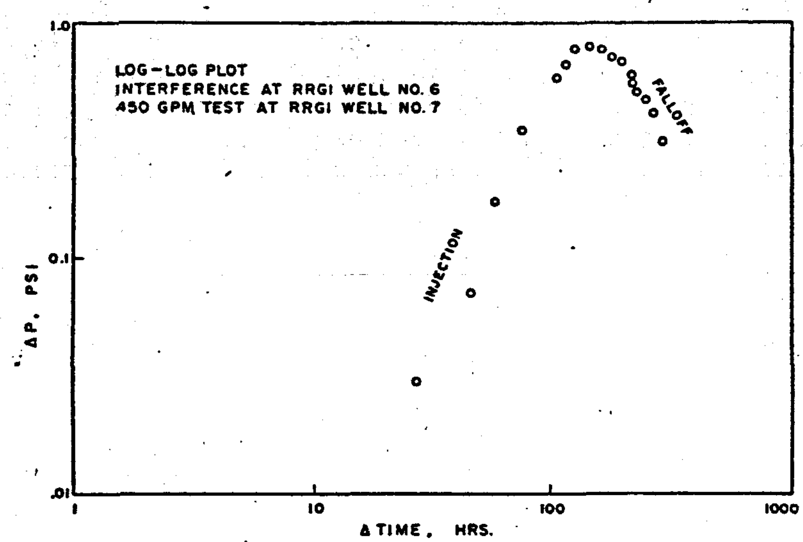

FIGURE 7. Interference Pressure Change Variation at RRGI-6.

A spinner survey[1] performed on RRGI-7 during the 450 gpm test indicated a nearly uniform fluid intake over the entire open hole. A previously performed spinner survey[1] in RRGI-6 has indicated that 50 percent of the fluid was being taken by the first 300 feet below the casing (a zone that is cased in RRGI-7). The remaining water was accepted uniformly throughout the lower part of the well, similar to RRGI-7. This can possibly explain the high 96 md permeability calculated from the interference test. Assuming the open hole in RRGI-6 to have the same 37 md permeability (as seen around RRGI-7) except the uppermost 300 feet, the effective permeability of this high fluid intake zone can be caluclated as 470 md. A similar permeability value is estimated from the RRGI-6 spinner survey data.

This permeable zone (from hereon called the 'thief zone') detected in RRGI-6 did not have any effect on pressure measurements at RRGI-7. Though the thief zone is cased off at RRGI-7, any direct communication (within reasonable distance from the wellbore) between the injection zone and the thief zone, should have resulted in a high positive skin factor due to partial penetration effects[11,12]. Careful investigation of geophysical logs by Orange[13] indicates that there are twenty feet of a high resistivity zone in RRGI-7 between 2140 feet and 2160 feet. This zone of high density rock is an indication of a tighter formation and may well be acting as a barrier between the uniform open hole and the thief zone. This anomaly is also seen in RRGI-6 at 1900 feet but it is weak.

From the injectivity test, spinner surveys and log evaluation, a picture of the injection zone has been hypothesized and is illustrated in Figure 8.

INJECTION PERFORMANCE PREDICTION

A two dimensional radial numerical simulator has been used to history match the injectivity tests. Using the average reservoir flow properties listed in Table 1 and the hypothesized reservoir as illustrated in Figure 8, the wellhead pressure performance trend of the 450 gpm test has been matched and is illustrated in Figure 9. The good match reinforces the applicability of the reservoir flow properties calculated from all the transient well tests.

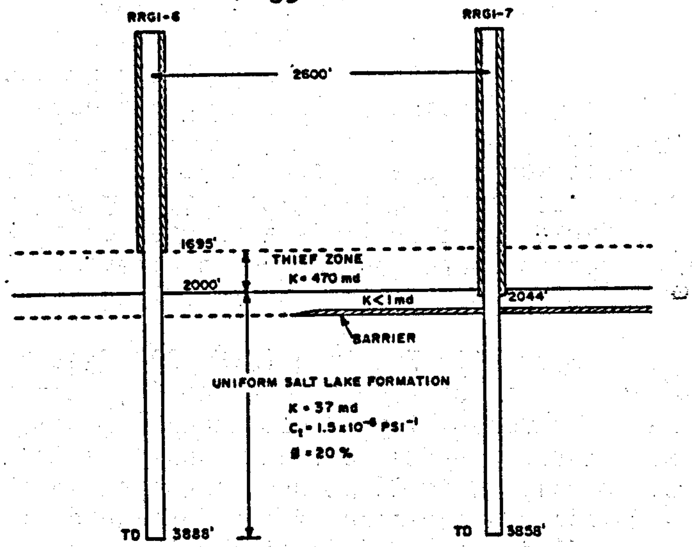

FIGURE 8. Hypothesized Injection Formation.

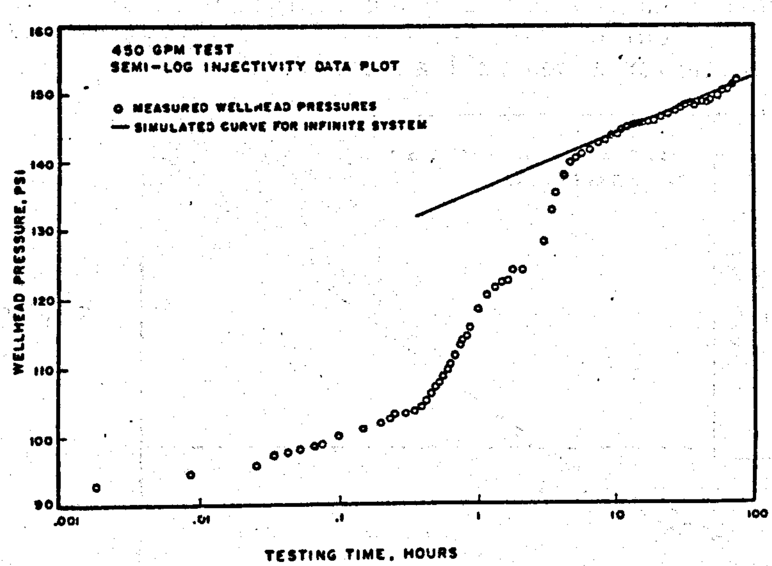

FIGURE 9. History Matching of RRGI-7 450 GPM Injection Test.

The reservoir model has been used to predict pressure behavior at RRGI-6 and 7. The properties of the injected fluid are 71°C brine with less than 4 percent NaCl (viscosity = 0.38 cp). Two possibilities for injection into the formation have been considered:

- Cased Thief Zone (the present situation)
- Uncased Thief Zone (perforating the casing and letting fluid flow into the thief zone).

In view of the uncertainty of the reservoir geology, several boundary conditions have been considered. For simplicity and because the conclusions are not substantially altered, only an infinite reservoir is presented in detail here.

Cased Thief Zone: Figure 10 illustrates the wellhead pressure rise with time at RRGI-7 with simultaneous injection of 1250 gpm into each RRGI-6 and 7. It approaches the 500 psi limit within a month. Even the presence of a possible sink to the north would have no effect at early times (prior to about four years of injection) because of its location at a great distance. The location of the Bridge Fault, whether it is a barrier or sink, will not alter this conclusion. Two options were considered to alleviate the injection problem - hydraulic fracturing of the well and drilling a new well.

Inducing a Massive Hydraulic Fracture (MHF) 300 feet high with each wing 2600 feet long would not significantly improve the injection potential. The relatively high formation permeability necessitates a highly conductive fracture that would need to be inches in width, a feat impossible to achieve. Even-such a fracture would provide only 20 to 25 percent increase in the injectivity capability[14,15]. A detailed evaluation of the MHF can be found in Reference 16 (in preparation). Drilling a new injection well with the intentions of minimizing pipeline length and meeting the wellhead pressure requirement was also investigated. Provided a sink is present on the northeast corner of the valley, a well drilled at about two miles north of RRGI-7 would satisfy the pressure requirements when 840 gpm is injected into each of the three wells for thirty years. Without definite evidence for the presence of such a sink, it is premature to plan for a new well at this time.

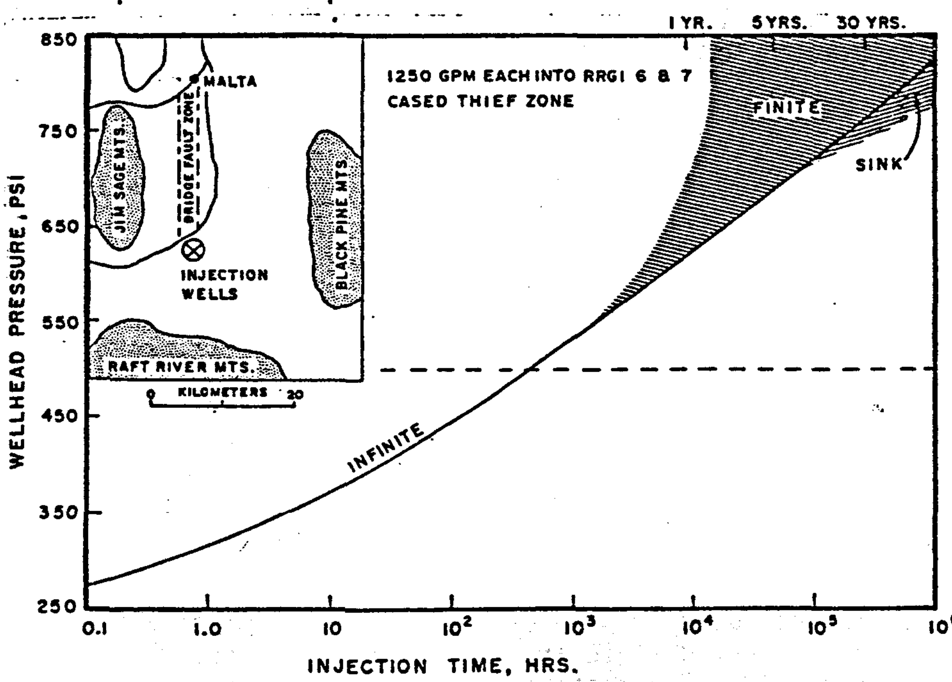

FIGURE 10. Cased Thief Zone.

Uncased Thief Zone: Injection of fluid into the thief zone introduces the possibility that fluid will migrate into overlying agricultural aquifers. The State of Idaho wishes to prevent this, although the thief zone may well be in poor contact with these aquifers. A numerical study has been performed to assess the pressure behavior upon uncasing the thief zone. Figure 11 illustrates the rise in wellhead pressure at RRGI-7 for simultaneous injection of 1250 gpm into each of the wells with the thief zone open to accept fluid. The radial extent of the thief zone is analogous to that of the lower part of the injection formation. An infinite reservoir will permit adequate injectivity for thirty years. However, any significant reservoir barrier would cause adverse pressure increases at earlier times, possibly within one to two years.

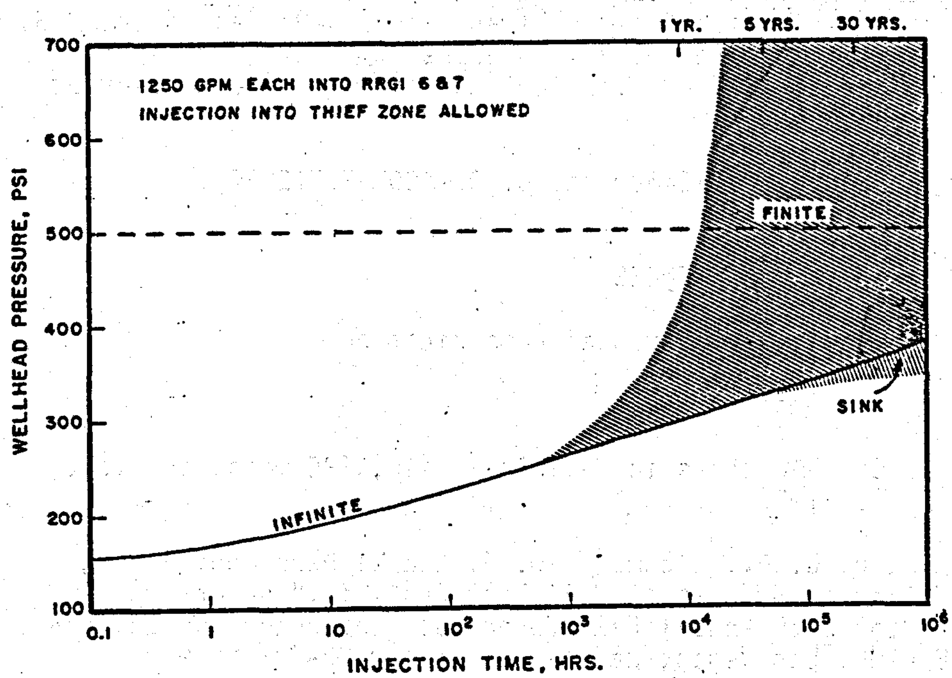

FIGURE 11. Uncased Thief Zone.

CONCLUSIONS

The present study warrants the following remarks:

- A combination of analyses of injection tests, the geology of the area, and spinner surveys have allowed us to define the injectivity potential of the Raft River geothermal site.

- The present well condition (not open to thief zone) will allow a two month injection of 1250 gpm into each RRGI-6 and 7 before the wellhead pressures approach 500 psi. A massive hydraulic fracture will not substantially improve injectivity, and success by drilling a new well is heavily dependent on the uncertain existence of a large sink near the site.

- Allowing the thief zone to accept fluid along with the present open hole will satisfy the injection program with an infinite reservoir. For a finite reservoir, an area greater than 450 square miles will be required.

- It is suggested that the present wells drilled to the producing horizons could solve the injection problem, but this may introduce the chances of early thermal and/or hydrological breakthrough to the producing formation.

- It is evident that detailed geological considerations (size and continuity of thief zone, location and potential of a sink or sinks, location and effectiveness of barriers) are critical to the injection design of the site.

ACKNOWLEDGEMENTS

Appreciation and thanks are due to Roy Mink and Susan Prestwich of the Department of Energy (DOE) and Max Dolenc, Dennis Goldman and Bob Hope of EG&G Idaho, Inc. for making the transient pressure data available to use. We also want to thank Scott Keys, Ulrich Schimschal and Richard Hodges of the U.S. Geological Survey for providing a preliminary interpretation of their spinner surveys. We thank John Schatz of Terra Tek for his review of the manuscript and his helpful suggestions.

This work was supported by DOE Contract No. DE-AC07-77ET28301.

REFERENCES

1. Schimschal, U. and Keys, W. S., personal communication.

2. Lee, J, personal communication.

3. Earlougher, Jr. R. C., "Advances in Well Analysis", SPE monograph Vol. 5, Dallas, Texas, 1977.

4. Mangold, D. C., Tsang, C. F., Lippmann, M. J. and Witherspoon, P. A., "A Study of Thermal Effects in Well Test Analysis," paper SPE 8232 presented at the 54th Annual Fall Technical Conference and Exhibition of SPE-AIME, Las Vegas, Nevada, September 23-26, 1979.

5. Williams, P. L., Mabey, D. R., Zohdy, A. A. R., Ackermann, H., Hoover, D. B., Pierce, K. L. and Oriel, S. S., "Geology and Geophysics of the Southern Raft River Valley Geothermal Area, Idaho, U.S.A.," Second U. N. Symposium on Development and Use of Geothermal Resources, San Francisco, pp. 1273-1282, 1975.

6. Mabey, D. R., Hoover, D.B., O'Donnell, J. E. and Wilson, C. W., "Reconnaissance Geophysical Studies of the Geothermal system in Southern Raft River Valley, Idaho," *Geophysics*, Vol. 43, pp. 1470-1484, 1978.

7. Ackermann, H.D., "Siesimic Refraction Study of the Raft River Geothermal Area, Idaho," *Geophysics*, Vol. 44, pp. 216-225, 1979.

8. Keys, W. S. and Sullivan, J. K., "Role of Borehole Geophysics in Defining the Physical Characterisitics of the Raft River Geothermal Reservoir, Idaho," *Geophysics*, Vol. 44, pp. 1116-1141, 1979.

9. Mink, L., personal communication.

10. Covington, H. R., "Deep Drilling - Raft River Geothermal Area, Idaho, Raft River Geothermal Injection Well No. 6," U.S. Geological Survey Open-File Report 79-1129, 1979.

11. Saidikowski, R. M., "Numerical Simulations of the Combined Effects of Wellbore Damage and Partial Penetration," paper SPE 8204 presented at the 54th Annual Fall Technical Conference and Exhibition of the SPE-AIME, Las Vegas, Nevada, September 23-26, 1979.

12. Kazemi, H., and Seith, M. S., "Effect of Anistropy and Stratification on Pressure Transient Analysis of Wells with Restricted Flow Entry," *Journal of Petroleum Technology*, May 1969, pp. 639-647.

13. Orange, A., personal communication.

14. McGuire, W. J. and Sikora, U. L., "The Effect of Vertical Fractures on Well Productivity," trans., AIME, 219, 1960, pp. 401-403.

15. Tinsley, J. M., Williams, Jr., J. R., Tiner, R. L., and Malone, W. T., "Vertical Fracture Height - Its Effect on Steady - State Production Increase," paper SPE 1900 presented at SPE 42nd Annual Fall Meeting, Houston, October 1-4, 1967.

16. Ahmed, U., Wolgemuth, K. M., Abou-Sayed, A. S., Schatz, J. F., and Jones, A. H., "The Potential for Increasing Injectivity at the Raft River Geothermal Site," Final Report to DOE (in preparation).