EVALUATION OF INJECTIVITY AT THE
RAFT RIVER GEOTHERMAL SITE

FINAL REPORT

By

U. Ahmed
K. M. Wolgemuth
A. S. Abou-Sayed
J. F. Schatz
A. H. Jones

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Terra Tek, Inc.
420 Wakara Way
Salt Lake City, Utah 84108

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SUMMARY

Operation of the 5 MWe power plant at the Raft River Geothermal Site in southern Idaho will require the disposal of 2500 gpm of water, either at the surface or by reinjection. The Idaho Department of Water Resources, because of concern about water quality, strongly favors the option of injection into zones that do not communicate with the known agricultural aquifers. The objective of this study was to evaluate the injection capability of the geologic formation at the location of the two present injection wells, RRGI-6 and RRGI-7.

This report presents our analysis of several injectivity tests performed by EG&G on well RRGI-7. The analysis was aided by available geological information about the area and preliminary results of spinner surveys conducted by the U.S. Geological Survey of wells RRGI-6 and RRGI-7. From the above information, we developed an interpretation of the thickness, continuity, and permeability of the injection formation. An important feature related to the injection formation is the "thief zone", a highly permeable horizon at about 1800 ft. depth which communicates from well RRGI-6 to shallower monitor wells but is cased off in RRGI-7. This zone is not itself an agricultural aquifer, but it is not known whether it is in communication with agricultural aquifers. A two dimensional radial numerical simulator with the parameters determined from the test analysis and available geological data was used to predict pressure vs. time at RRGI-6 and RRGI-7 for different injection schemes. The current conditions (with RRGI-6 open to the thief zone and RRGI-7 cased) would allow a total of 1600 gpm for 30 years, assuming an infinite reservoir. This is not adequate to fulfill needs. The option of stimulating RRGI-7 by a massive hydraulic fracture has been carefully evaluated and injectivity could

not be improved by more than about 20%.

An alternative injection scheme was considered:

- Injection into the thief zone by perforating the casing in RRGI-7. This would satisfy injection requirements of 2500 gpm assuming that the reservoir is at least 450 square miles. However, present data cannot tell us if the reservoir is this large. In the case that thief zone injection is not a complete solution to the injection problem, several other possible schemes have been suggested to provide the necessary disposal volume:
- Utilizing a portion of the spent brine for irrigation after water treatment. Since the present wells are capable of 1600 gpm injection (infinite reservoir), 900 gpm of surface disposal would satisfy the injection requirements.
- Utilizing other shallow aquifers. Risk exists of leakage into agricultural aquifers.
- Drilling a new well into the Salt Lake formation. Well location must be carefully determined with respect to the present well and total reservoir characteristics.
- Injecting into the production zone. This includes the risk of thermal and/or hydrological breakthrough.

We believe that these four merit further investigation and that a combination of them should be considered for an integrated approach to provide the optimum disposal scheme. Each of these options require careful evaluation with respect to risks, benefits, and cost. In addition, well testing of greater duration is necessary to determine the long term injection behavior of the reservoir and define the flow characteristics of the reservoir's boundaries.

1. INTRODUCTION

The development of the 5 MWe binary cycle electric power plant at the Raft River Geothermal Site in southern Idaho (Figure 1) will require the disposal of approximately 2500 gpm of fluid. The two injection wells which have been drilled, RRGI-6 and RRGI-7 (Figure 2), provide an injection capacity of 1600 gpm combined. This is based on a proposed 30 year lifetime of the plant and a maximum wellhead pressure of 500 psi, a constraint imposed to prevent fracturing of the injection formation.

A series of injection tests into RRGI-7 were conducted by EG&G during August, 1979. These included 750 gpm flow for 4 hours, 620 gpm flow for 8 hours, and 450 gpm flow for 96 hours. The transient pressure data of these tests have been analyzed to characterize the injection capability of the formation. The available geological information about the area and preliminary results of spinner surveys performed by the U.S. Geological Survey (Keys and Schimschal, personel communication, 1979) have been included in the injectivity predictions.

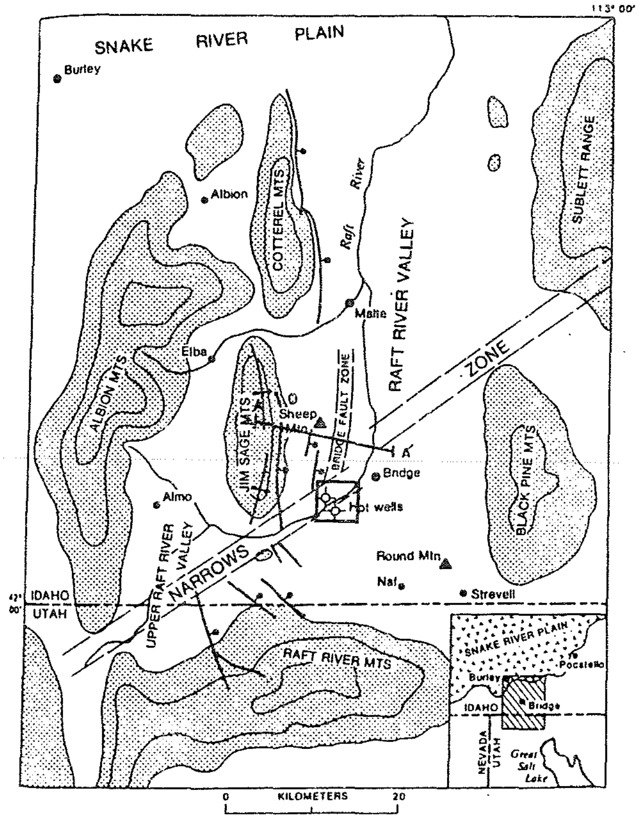

FIGURE 1. Map of the Raft River Valley area. (From Mabey et al., 1978).

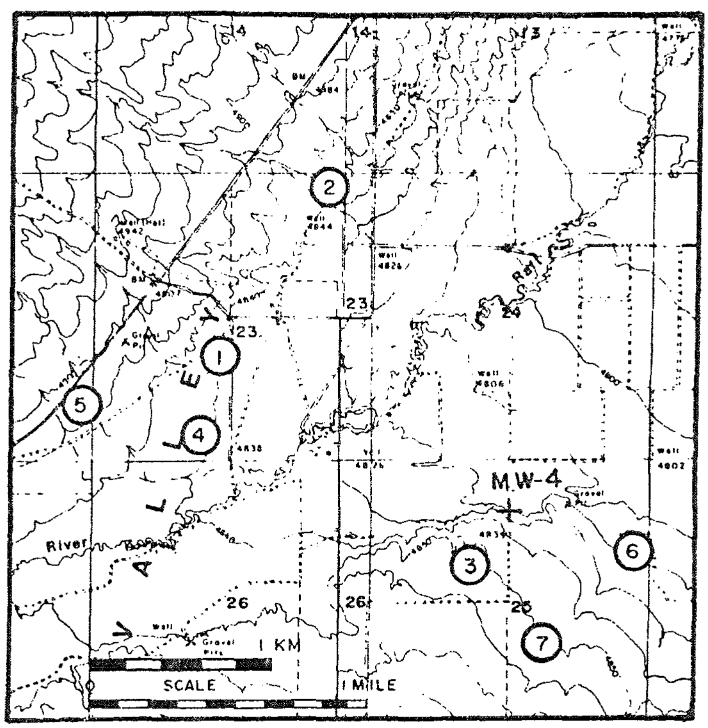

FIGURE 2. Well locations at the Raft River site. (Enlarged square section in Figure 1)

2. GEOLOGY AND HYDROLOGY OF POTENTIAL INJECTION ZONES

The Raft River geothermal reservoir is located at the northern edge of the Basin and Range province just south of the Snake River plain. Williams et al. (1975) described the geology of the Raft River Valley as a north trending late Cenozoic downwarp bounded by faults on the west, south and east (Figure 1). Pleistocene alluvium and Miocene-Pliocene tuffaceous sediments, conglomerates, and felsic volcanic rocks are found to a depth of about 5200 feet. The dominant faulting from within the reservoir includes the north trending Bridge Fault and the northeast trending Narrows Zone. While the Bridge Fault does display some surface expression, the Narrows Zone is a poorly understood structure interpreted from geophysical data. Mabey et al. (1979) suggest that it may be a shear zone within the basement rocks. Hot water production apparently comes from deep circulating water that rises at the intersection of the Bridge Fault Zone and the Narrows Zone and then spreads laterally within the lower portions of the sedimentary section.

The stratigraphy of the portion of the reservoir considered for injection is shown in Figures 3 and 4. Below a thin cover of alluvium lie Tertiary sediments to a depth of about 5200 feet. Below this lies a metamorphosed transition zone of quartzite and schist and then Precambrian quartz monzonite below 5800 feet. The Tertiary sediments are divided into the Raft River Formation and the Salt Lake Formation. The Raft River Formation consists of lake and stream deposits that accumulated on the eroded surface of the Salt Lake Formation (Walter et al., 1970) and is about 1200 feet thick in this portion of the reservoir.

The Salt Lake Formation consists of sedimentary and volcanic rocks of Pliocene age. In the region of the injection wells it is composed predominantly of tuffaceous siltstone and sandstone with minor section of gravel and

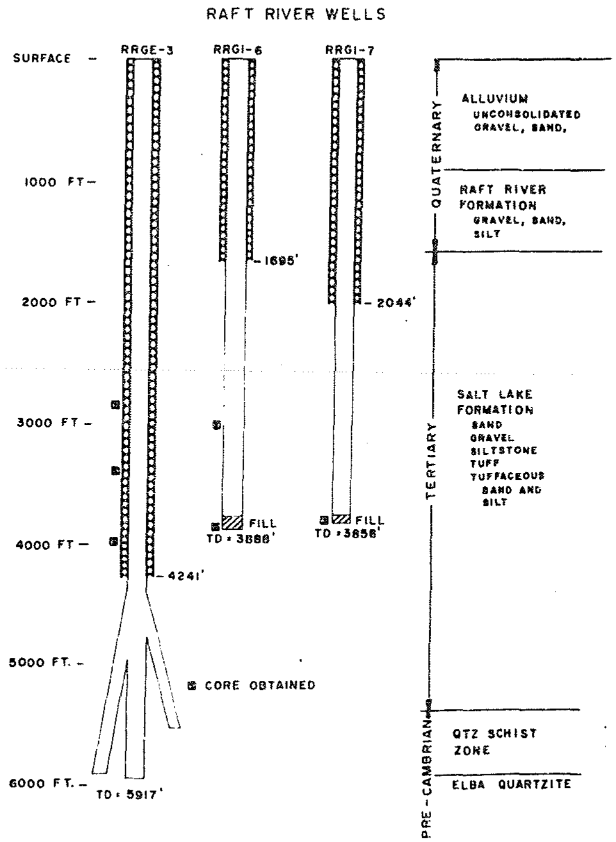

Figure 3. Schematic of Wells 3, 6 and 7.
(Compiled from EG&G Technical Reports)

sand or poorly consolidated sand (Covington, 1979). Ackermann (1979) has utilized the results of 25 seismic refraction spreads to calculate seismic velocities within the valley. The resulting velocities vary laterally supporting the general concept that the basin fill is a series of coalescing alluvial fans which have been reworked by the Raft River.

A section representative of the injection portion of the reservoir has near-surface velocities of abut 1.8 km/sec. which gradually increase with depth, reaching values of about 3.0 km/sec. at depths of roughly 2800 feet. For a basin filled with clastic sediments, this type of velocity function

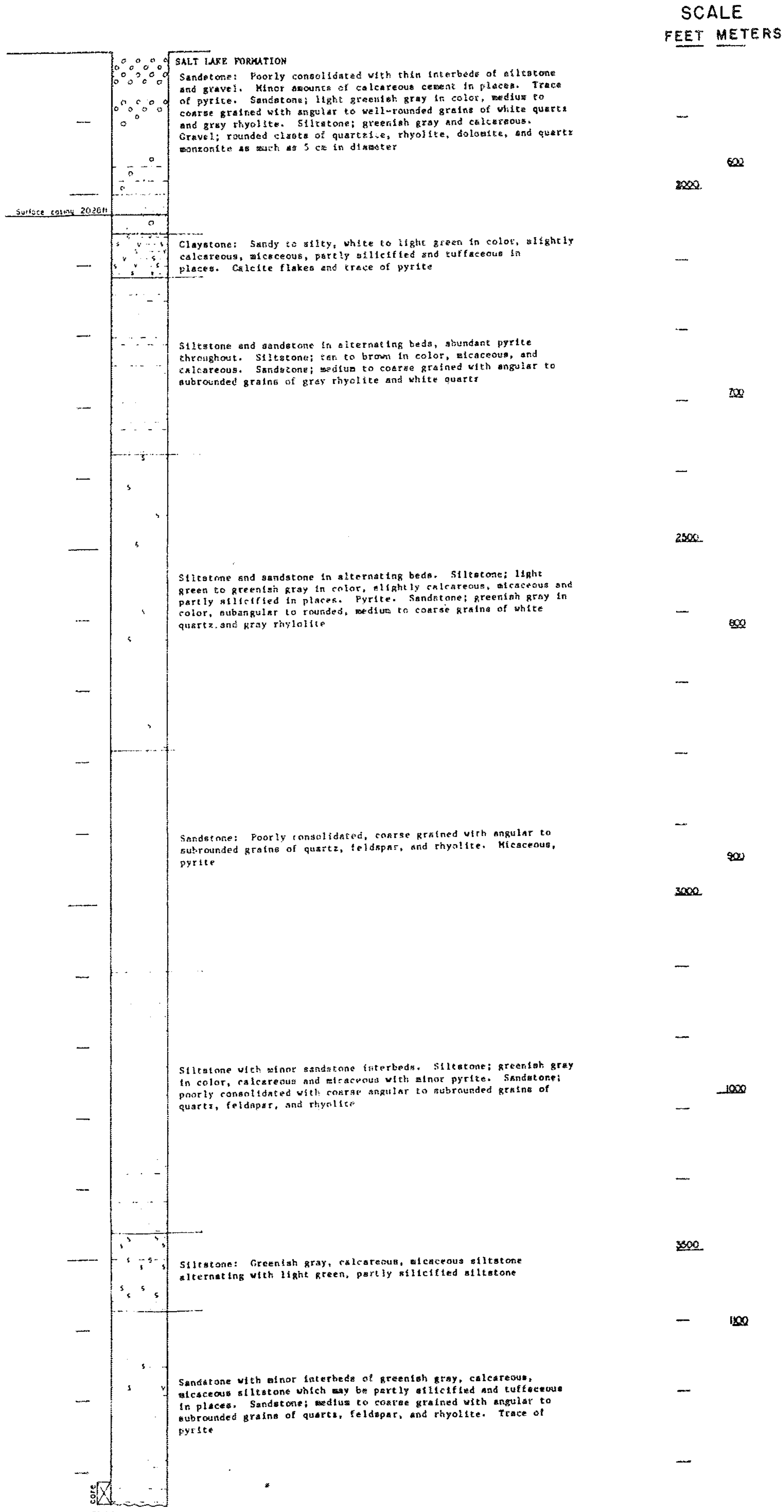

FIGURE 4.

Detailed stratigraphy of RRGI-7. (From Covington, 1979a).

indicates unconsolidated or very weakly consolidated near-surface beds which gradually become indurated with depth (Ackermann, 1979). A velocity of 3.0 km/sec. represents a well indurated though possibly porous rock.

The lateral changes observed in seismic velocity may correspond to zones where sediments are hydrothermally altered. In general, the flowing hot wells in the valley occur near the boundary between inferred shallow altered and unaltered rocks.

A critical parameter in the reservoir modelling and predictions presented in this report is whether the reservoir is infinite or bounded. The lateral boundaries appear to be defined by the mountains to the east, south and west. The Black Pine Mountains, composed of faulted Pennsylvanian and Permian sedimentary rocks, lie at a distance of 10 miles east of the geothermal site. To the south, 6 miles away, are the Raft River Mountains consisting of a gneiss-dome complex mantled by Precambrian and lower Paleozoic metasedimentary rocks and by allochthonous upper Paleozoic sedimentary rocks (Williams et al., 1978). Since these are metamorphic rocks, they are more likely to be barriers to flow. However, the nature of the zone between the valley and the mountains is poorly understood. A highly brecciated fault zone would permit substantial water flow.

The Jim Sage Mountains, 3 miles west of the geothermal site, are composed of Tertiary rhyolites and tuffaceous sediments. On the basis of reconnaissance geophysical studies, Mabey et al. (1978) have suggested that 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 (Figure 5). Furthermore, these rocks are highly deformed (Keys and Sullivan, 1979). Although no deep boreholes have been drilled through the Jim Sage Mountains, apparently the Salt Lake Formation sediments extend beneath

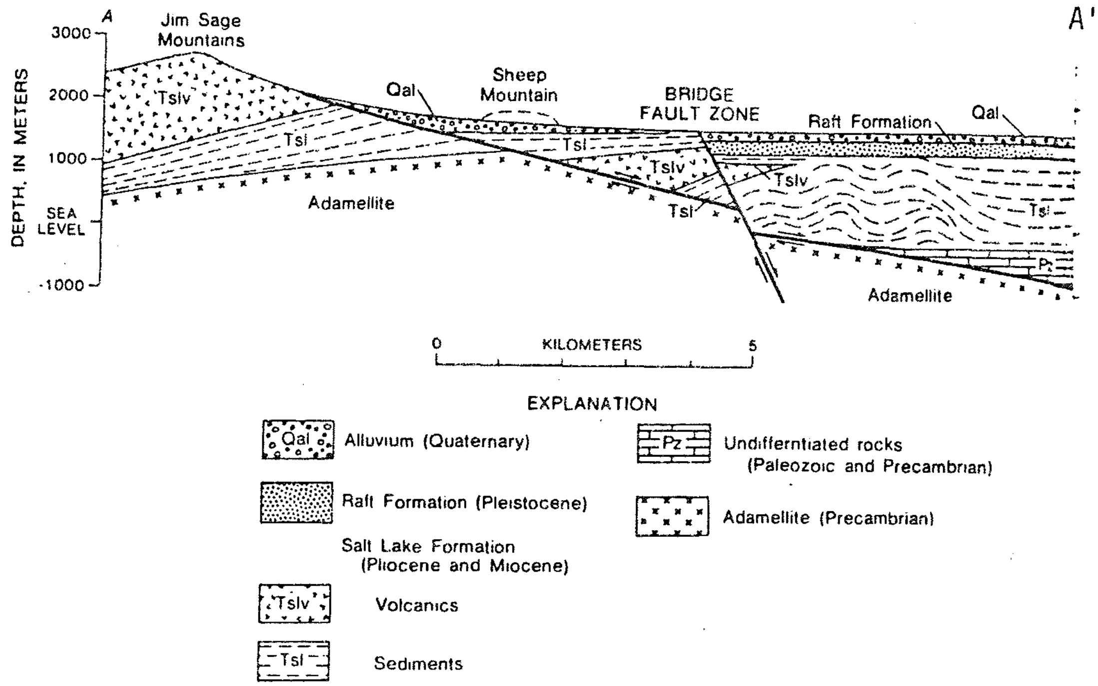

Figure 5. Interpreted section across the west side of the southern Raft River Valley. Location of section is shown in Figure 1. (From Mabey et al., 1978)

them. We therefore consider that this boundary of the geothermal resource is less likely to be a barrier to flow.

Since the Raft River Valley is bounded on the east, south, and west, ground-water flow is northward toward the Snake River Plain. About 30 miles north of the geothermal site, Snake River Plain basalts underlie the Salt Lake Formation at a depth of ~2000 feet (Mink, personal communication, 1979). These are highly permeable rocks and may serve as an ultimate sink for the spent geothermal fluid.

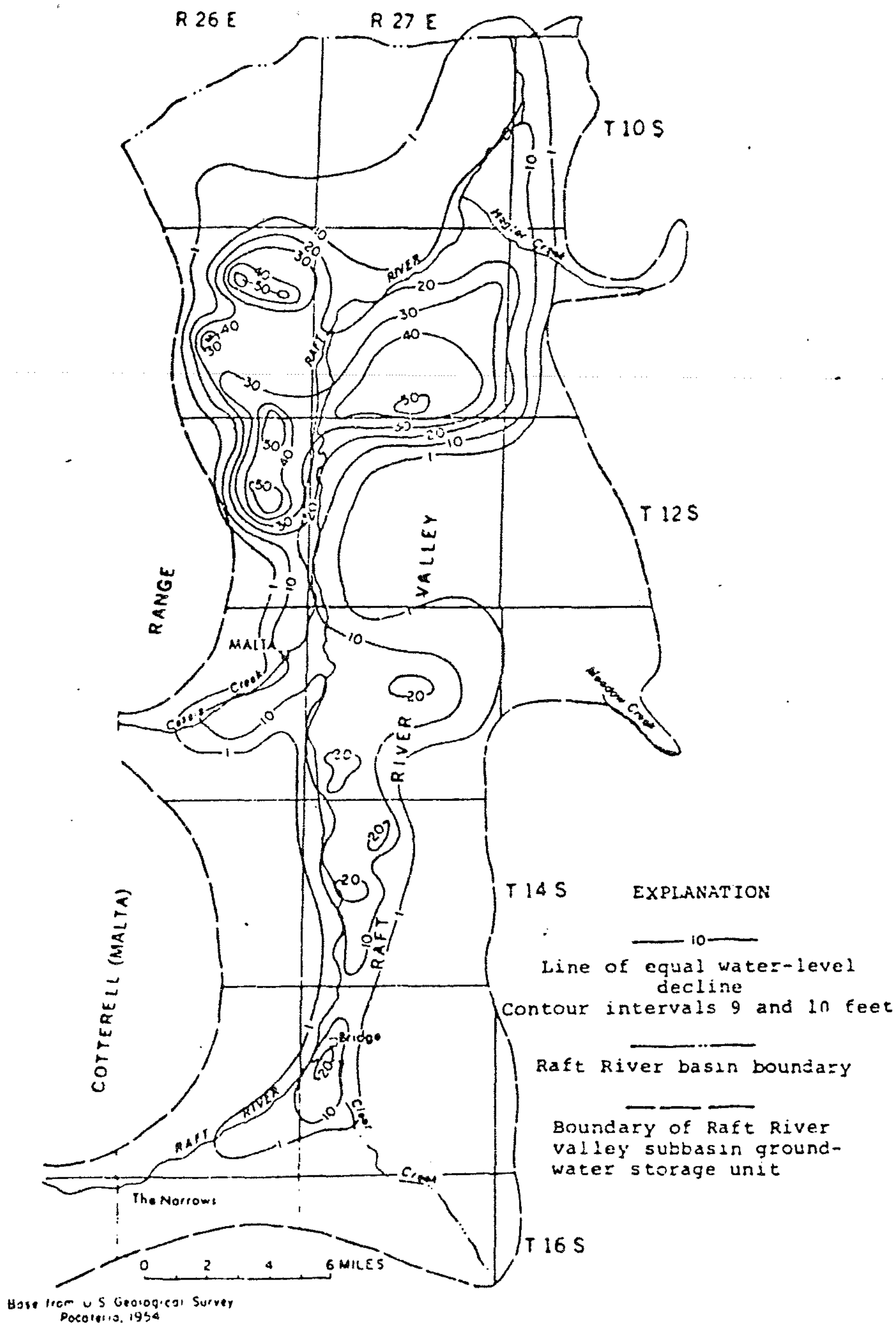

FIGURE 6. Net water-level change in Raft River Valley subbasin. Spring of 1952 to Spring of 1966. (From Walker et al., 1970)

Hydrology of the Raft River Valley Subbasin

The water resources of the Raft River Basin have been documented by Walker et al. (1970). The dominant use of water is for irrigation but the potential farming acreage far exceeds that which could be irrigated with the estimated annual water yield. Because of declining water levels, the valley was closed in 1963 to further issuance of ground-water use permits. As shown in Figure 6, the greatest net water level decline has occurred in lower Raft River Valley north of Malta, although some has taken place in the vicinity of the geothermal site.

Water for irrigation purposes is generally drawn from the upper unit of the Salt Lake Formation and the combined alluvium and Raft River Formation. Where interbedded basalt occurs, it also is a good water bearing unit (Walker et al., 1970). The exact thickness of individual units generally cannot be determined since few wells penetrate the full thickness. The lower and middle units of the Salt Lake Formation have lower permeability and therefore yields are too low for economic use in irrigation.

Potential Injection Zones

Three injection zones, all in the Salt Lake Formation, may be considered at depths below the aquifers being pumped for irrigation: (1) the highly permeable zone at depths between 1700 feet and 2000 feet, which accept approximately 50% of the water in RRGI-6 (this zone is called the "thief zone"), (2) present open hole section from 2100 feet to the bottom of the wells, and (3) the lower section of the Salt Lake Formation just above the quartzite which would require drilling the injection wells deeper.

The thief zone is a zone of poorly consolidated sediments composed of 60 to 80 percent sand and 20 to 40 percent gravel (Covington, 1979). A spinner survey done by the U.S. Geological Survey revealed that 50 percent of the water being injected into RRGI-6 during a well test was going into the formation within 300 feet of the bottom of the casing (Keys and Schimschal, personal communication, 1979). The injection test also caused a water level rise in monitor well #4 located 2600 feet away (Well MW-4 in Figure 2), indicating a direct connection between the thief zone and the upper unit of the Salt Lake Formation. A substantial flux of injection water upward would cause some risk of polluting the agricultural aquifer since the geothermal water has a fluoride content of 7 ppm which is unacceptable for irrigation.

The second potential zone for injection is the section shown in RRGI-7 beginning at 2100 feet to the bottom of the hole. The top 300 feet is poorly consolidated sand (Covington, 1979) which has resulted in a severe washout to about 20 inch diameter (a 12½ inch bit was used). The spinner survey by the U.S. Geological Survey indicates that this zone takes water at a slightly higher rate than the remainder of the hole. This open hole section has been evaluated by well testing and is reported in the next section.

The final option for fluid injection into the Salt Lake Formation is to drill the wells deeper to the contact with the metamorphic rocks and perhaps into the quartz monzonite. This includes the risk of thermal and/or hydrothermal breakthrough or of intersecting the fractures which supply hot water to RRGE-3. This factor, in addition to the high cost of drilling, are reasons to consider this only as a last resort.

3. WELL TEST ANALYSIS

3.1 Background

Reliable information about *in-situ* reservoir conditions is important to plan a long term injection program and to predict reservoir performance under various modes of operation. This information can be obtained from transient pressure tests, spinner surveys and a detailed geological understanding of the area.

Conventional transient injectivity test analysis assumes that the mobilities of the injected fluid and the *in-situ* fluid are the same (Earlougher, 1977; Lee, personal communication, 1979). This condition is not achieved during injection when the injected fluid and *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 (Earlougher, 1977; Mangold et al., 1979). Thermal expansion (during injection) and contraction (during falloff) of the wellbore fluid influences wellhead pressure. Therefore, greater emphasis has been placed on interpreting the bottom hole falloff data.

3.2 Injection Test Analysis

3.2.1 1978 Tests

During August, 1978, EG&G Idaho, Inc. conducted a constant step down flow rate injection test (840, 675 and 475 gpm) and a 5½ hour 400 gpm injection test into RRGI-7. No falloff data were recorded and during injection only wellhead pressure and temperature were recorded.

The analysis of the 1978 tests was hindered by exceptional wellbore storage effects, uncertainty whether the reservoir was at equilibrium before the tests started, uncertain flow rate, and lack of information regarding bottom hole pressures, fall off data, static wellhead pressure, and injected fluid properties.

3.2.2 <u>1979 Tests</u>

During August-September, 1979, three injection tests were conducted into RRGI-7 at constant rates of 750, 620 and 450 gpm for 5½, 8 and 96 hours respectively. Bottom hole pressure and temperature were recorded with a Hewlett-Packard (HP) probe and wellhead pressure and temperature 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 reequilibration. All three injectivity tests provided consistent results.

<u>750 GPM Falloff Data Analysis</u>: Following 5½ hours of constant rate injection, the well was shut in and pressure and temperature falloff were recorded both bottom hole and at the wellhead. Figure 7 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 0.03 hours and the formation compressibility is calculated to be a 1.33×10^{-6} psi^{-1}. Figure 8 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 correct semi-log straight line the average formation permeability of the open hole was calculated as 37 md and a skin factor of +0.1 for the well. When the bottom hole temperature started dropping significantly, the pressure decay rate reduced. Figure 9 is the semi-log plot of pressure and temperature

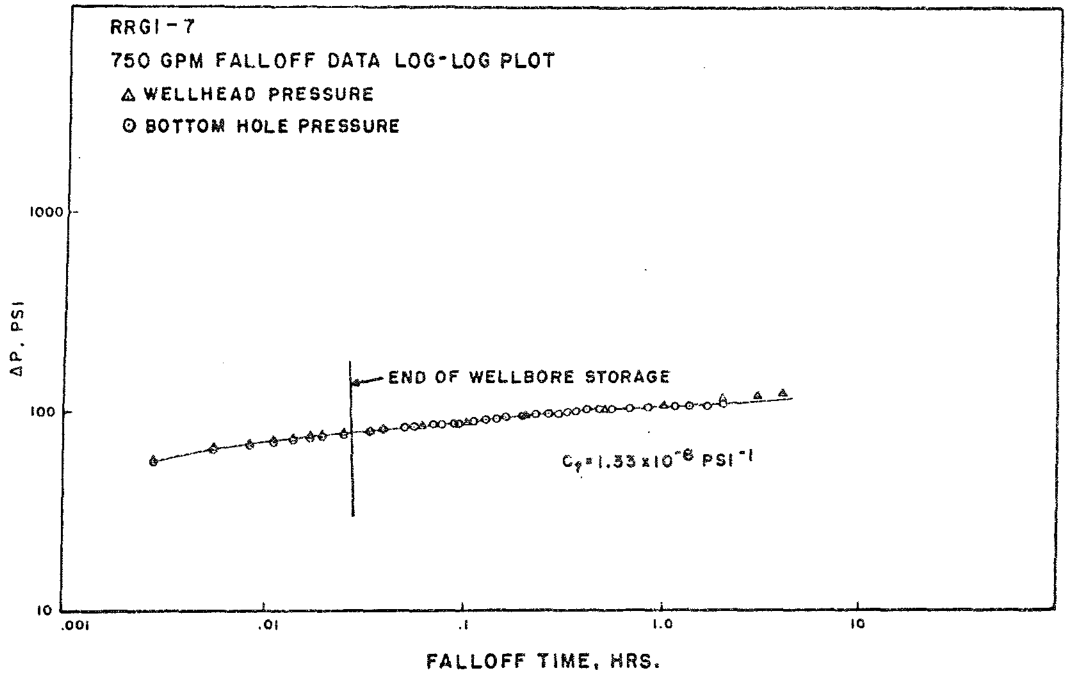

FIGURE 7. Log-log plot of pressure changes versus time, 750 gpm falloff.

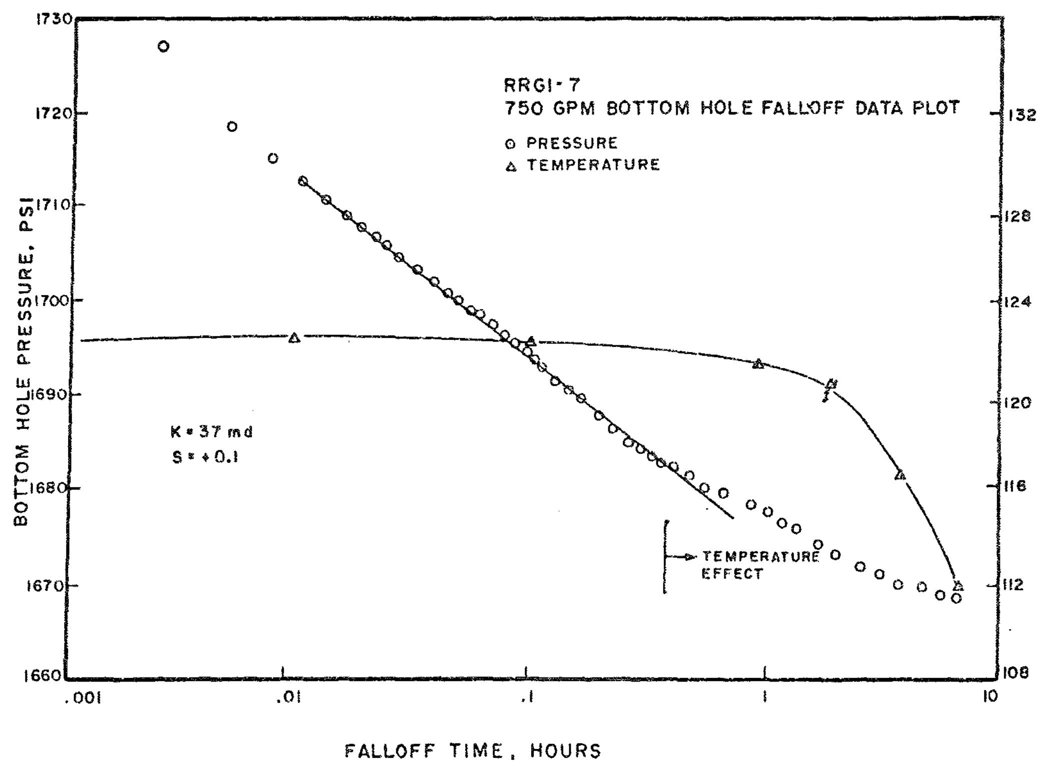

FIGURE 8. Semi-log plot of downhole pressure and temperature, 750 gpm falloff.

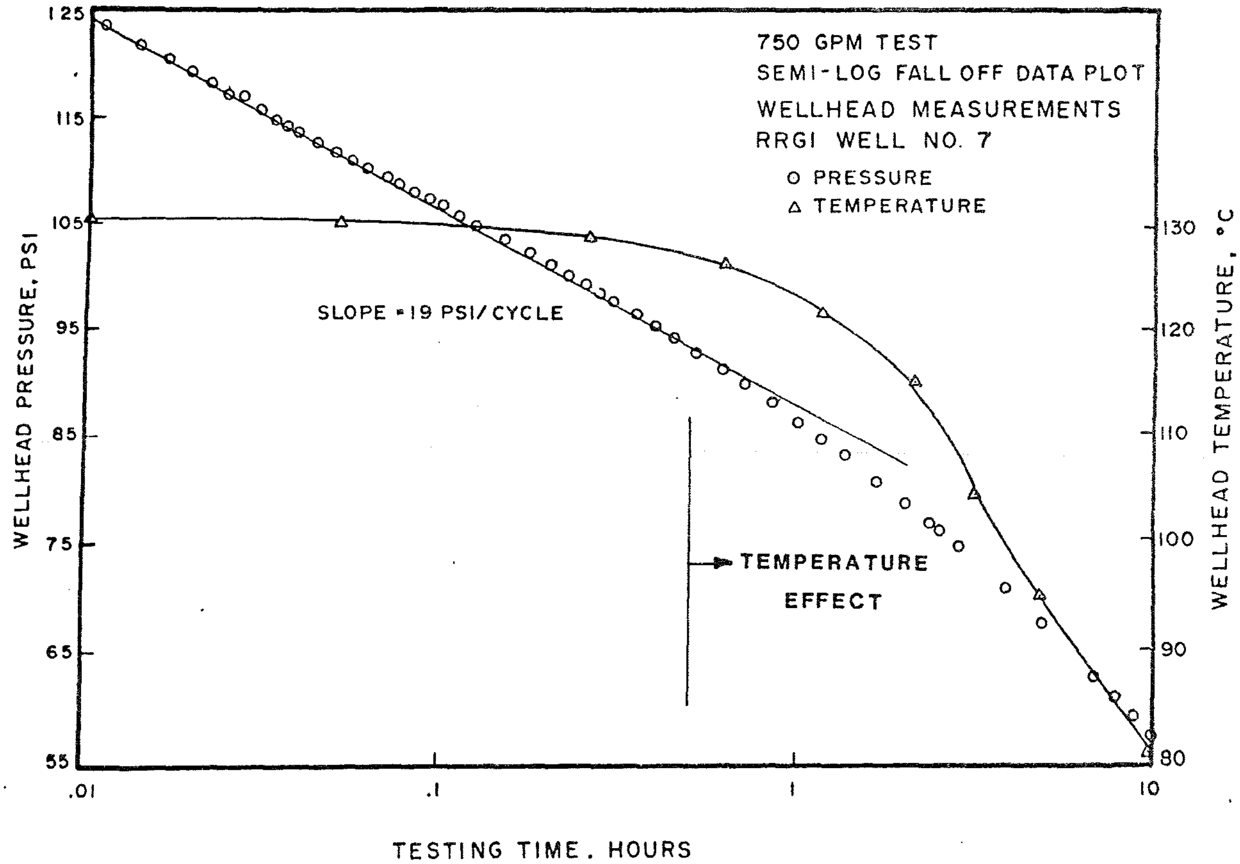

Figure 9. Semi-log plot of wellhead pressure and temperature, 750 gpm falloff.

falloff with time as recorded at the wellhead. The wellhead temperature remained fairly constant at 127°C for about 0.8 hours. Good pressure data was recorded. From the semi-log straight line the average formation permeability of the open hole was calculated as 36 md and the well showed 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.

<u>750 GPM Injectivity Data Analysis</u>: 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. Details of the injectivity data analysis and the temperature compensation are presented in Appendix A. Calculated average permeability is 38 md, total system compressibility is 1.47×10^{6} psi ^{1}, and the well indicates negligible skin factor (-0.3).

<u>620 GPM Falloff Data Analysis</u>: Following eight hours of constant rate injection, the well was shut in and pressure and temperature falloff were recorded at both bottom hole and at the wellhead. Figure 10 is the log-log plot of the pressure changes versus time for both the bottom hole and wellhead measurements. The wellbore storage effects ceased after about 0.02 hours; the formation compressibility is calculated to be 1.6×10^{6} psi ^{1}. Figure 11 is the semi-log plot of pressure and temperature falloff with time as recorded downhole. The bottom temperature remained fairly constant at 123°C for about 0.8 hours and good pressure data was recorded during that time. From the correct semi-log straight line the average formation permeability of the open hole is calculated as 37 md and the well had a skin factor of +0.8. When the bottom hole temperature started dropping significantly, the effect on pressure was similar to the 750 gpm test. Figure 12 is the semi-log plot of pressure and temperature falloff with time as recorded at the wellhead. The wellhead temperature remained fairly constant for about 0.6 hours and good pressure data was recorded. From the correct semi-log straight line, the average formation permeability of the open hole was calculated as 38 md and the well shows a skin factor of -0.1. When wellhead temperature started dropping significantly, a similar effect on pressure occurred as in the 750 gpm test.

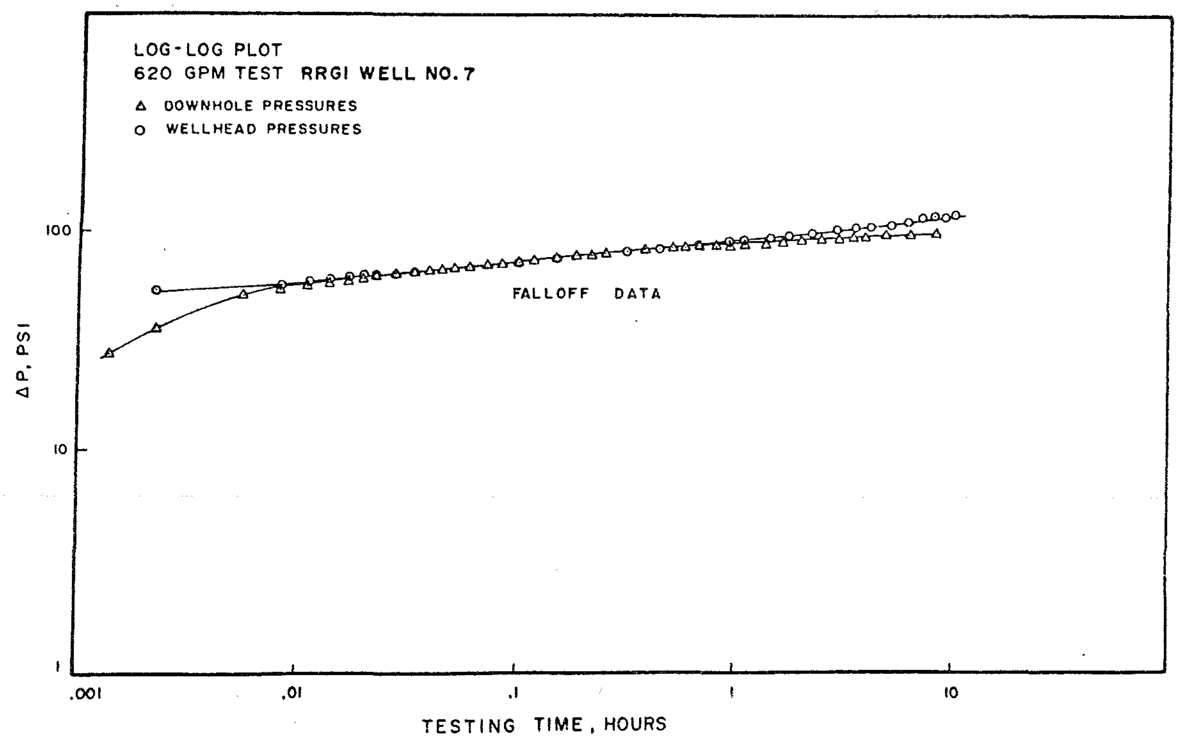

FIGURE 10. Log-log plot of pressure changes versus time, 620 gpm falloff.

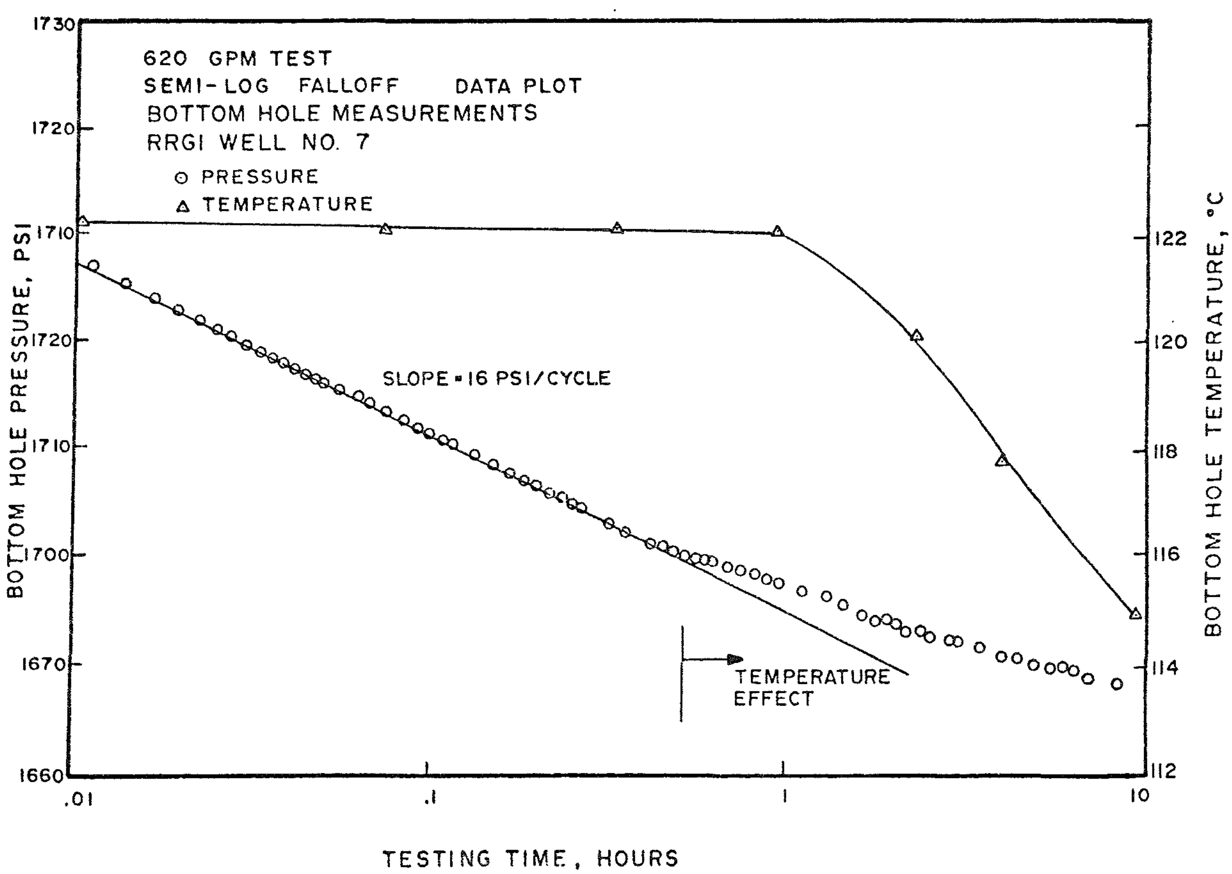

FIGURE 11. Semi-log plot of downhole pressure and temperature 620 gpm falloff.

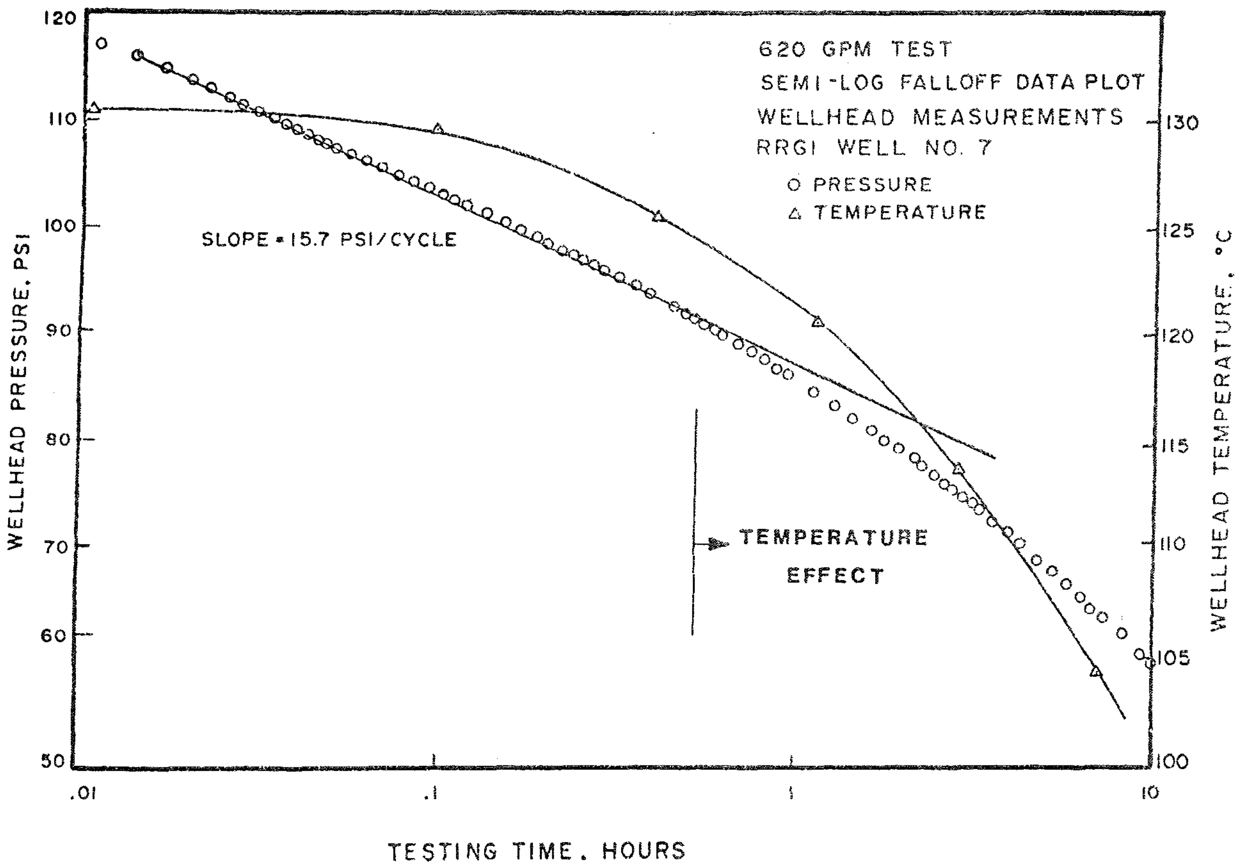

Figure 12. Semi-log plot of wellhead pressure and temperature, 620 gpm falloff.

620 GPM Injectivity Data Analysis: The injectivity data analysis using simple temperature compensation resulted in similar results to the falloff data analysis and is discussed in detail in Appendix A. Calculated average permeability is 33 md, total system compressibility is 1.5×10^{-6} psi^{-1}, and the well indicates negligible skin factor (+0.8 to -0.1).

450 GPM Falloff Data Analysis: Following ninety-six hours of constant rate injection, the well was shut-in and pressure and temperature falloff were recorded bottom-hole and at the wellhead. Figure 13 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 0.03 hours and the

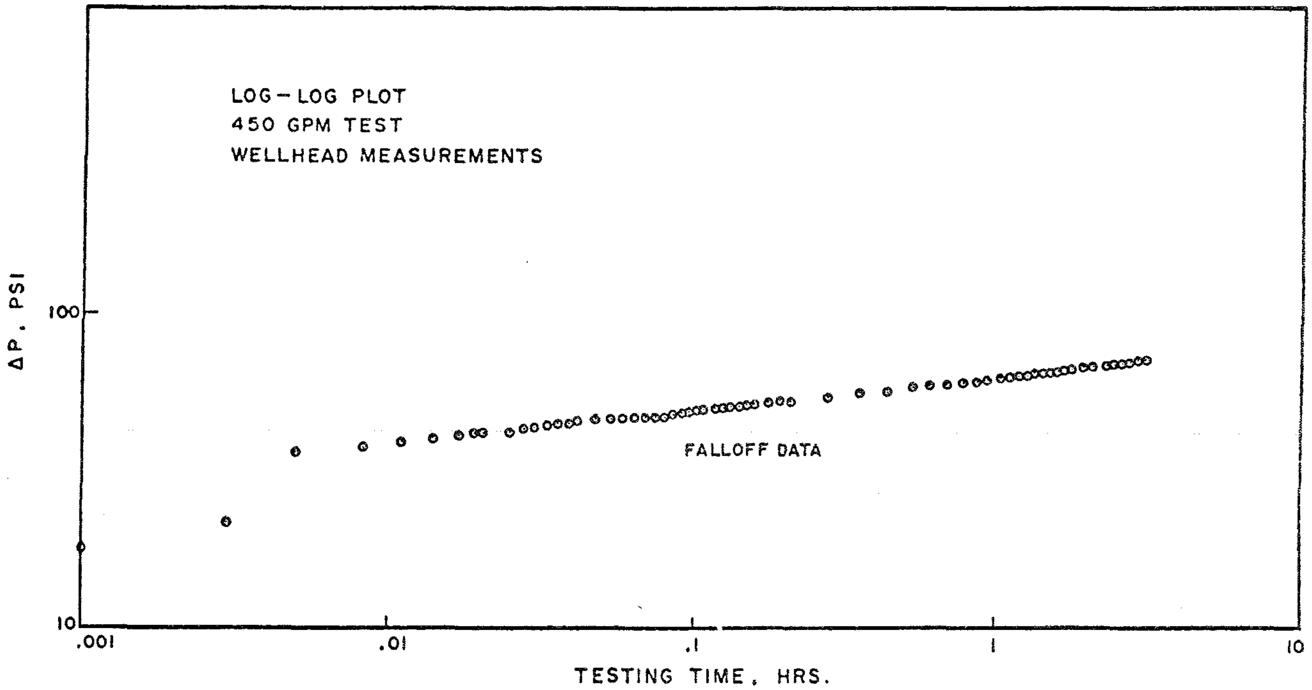

Figure 13. Log-log plot of pressure changes versus time, 450 gpm falloff.

formation compressibility was calculated as 1.54×10^{-6} psi^{-1}. Figure 14 is the semi-log plot of pressure and temperature falloff with time as recorded downhole. The bottom hole temperature remained fairly constant at 120°C for about ten hours. From the correct semi-log straight line the average formation permability of the open hole was calculated as 36 md and the well had a zero skin factor. Figure 15 is the semi-log plot of pressure and temperature falloff with time as recorded at the wellhead. The wellhead temperature remained fairly constant for about 0.7 hours and good pressure data was recorded to that time. From the correct semi-log straight line the average formation permeability was calculated as 35 md and the well shows a zero skin

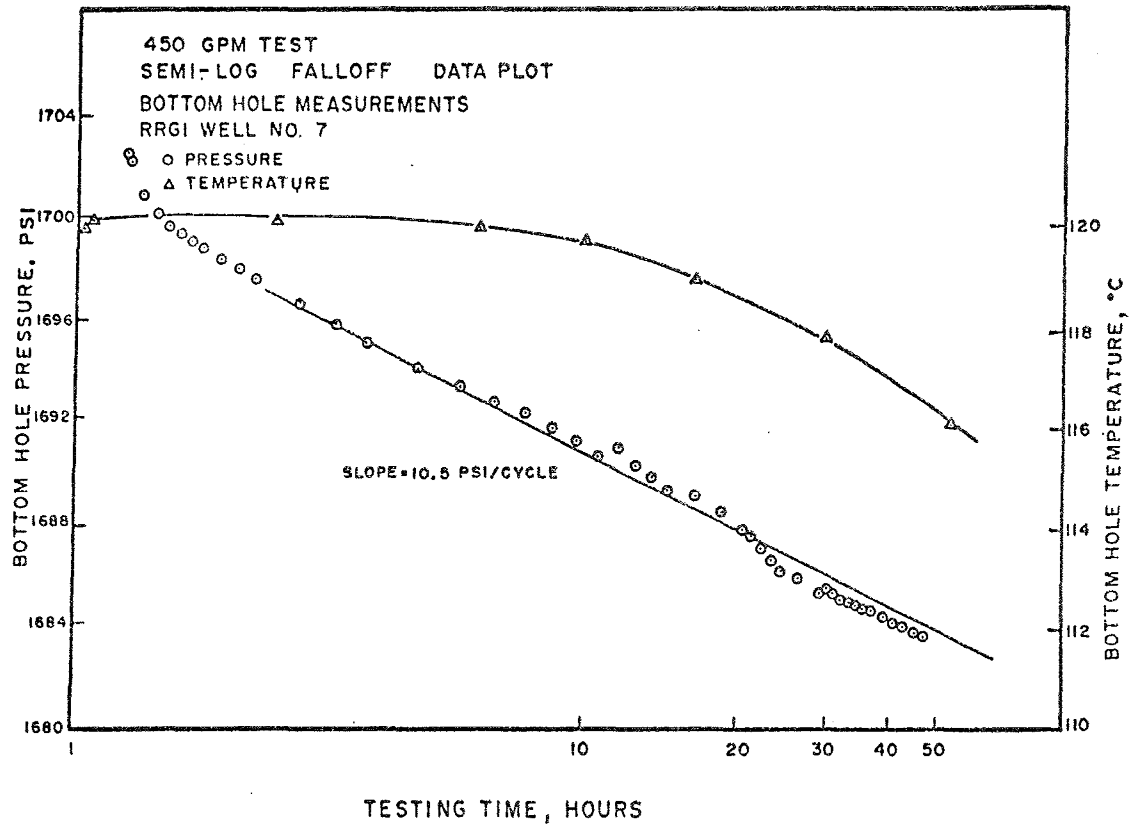

FIGURE 14. Semi-log plot of downhole pressure and temperature, 450 gpm falloff.

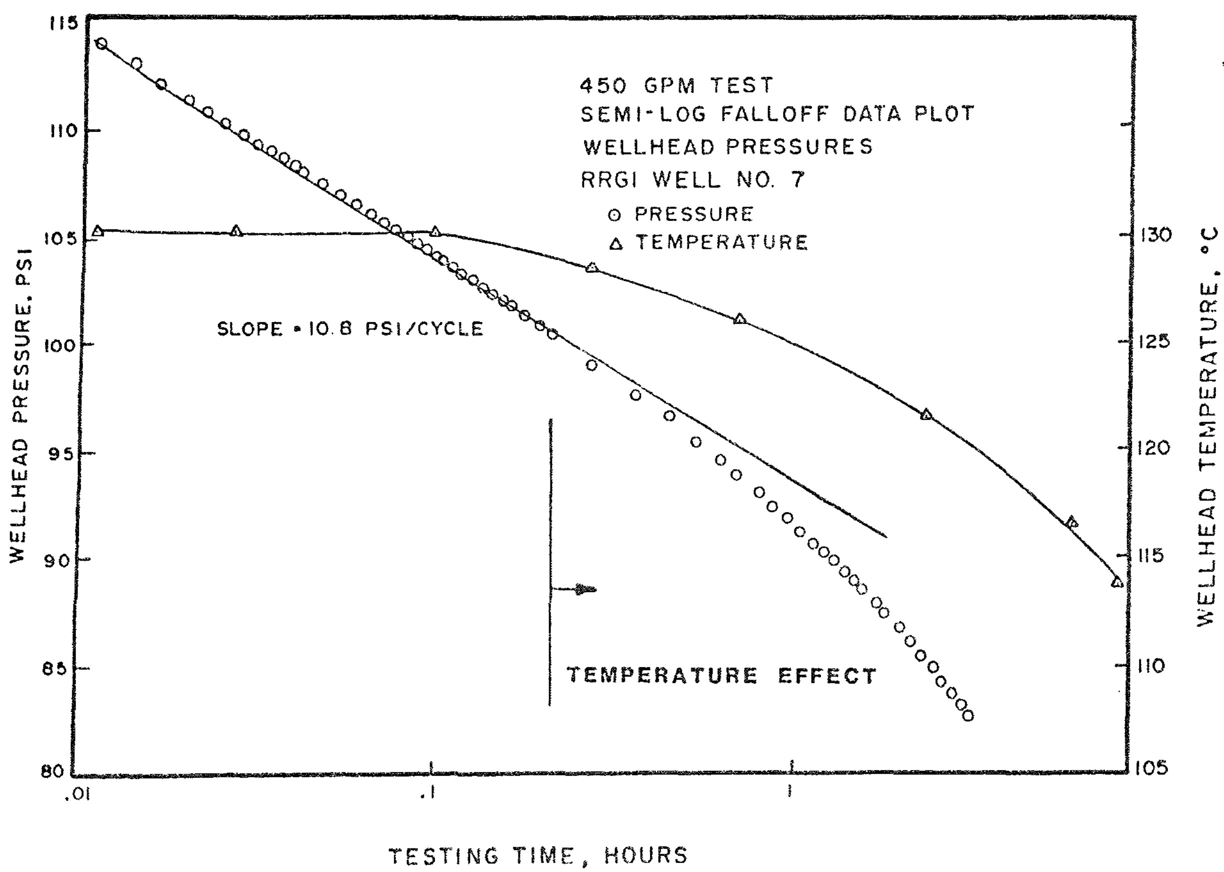

FIGURE 15. Semi-log plot of wellhead pressure and temperature, 450 gpm falloff

factor. When the wellhead temperature started dropping significantly, its effect on the pressure is similar to that of the 750 and 620 gpm test.

<u>450 GPM Injectivity Data Analysis</u>: The injectivity data analysis using simple temperature compensation resulted in similar results to the falloff data analysis and is discussed in detail in Appendix A. Calculated average permeability is 40 md, total system compressibility is 1.55×10^{-6} psi^{-1} and the well indicates zero skin factor.

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 ± 10^{-6} psi^{-1} total system compressibility, and negligible skin factor (+0.8 to -0.3). These reservoir properties correspond to a 5,800 foot radius of investigation.

TABLE 1

WELL AND RESERVOIR PROPERTIES AROUND RRGI-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
Fluid Viscosity	0.285 cp
Initial Reservoir Pressure	1677 psi
Wellbore Storage Coefficient	0.00227 res. bbls/psi
Dimensionless Wellbore Storage Coefficient	22.4

Table I (Cont.)

TEST	PERMEABILITY md	SKIN FACTOR	TOTAL COMPRESSIBILITY psi^{-1}	RADIUS OF INVESTIGATION ft
750 gpm	36.9	+0.1 to 0.3	1.4×10^{-6}	4700
620 gpm	35.1	+0.8 to 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 16 is the log-log plot of the wellhead pressure changes with time. Using the 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. This is substantially higher than the 37 md measured around RRGI-7. This implies the liklihood of a zone of high permeability within the vicinity of the two wells.

A spinner survey performed on RRGI-7 by the U.S. Geological Survey (Keys and Schimschal, personal communication, 1979) during the 450 gpm test indicated a nearly uniform fluid intake over the entire open hole except the first hundred feet below casing where no fluid influx was noticed. A spinner survey of RRGI-6 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 fluid was accepted uniformly throughout the remainder of the well. These

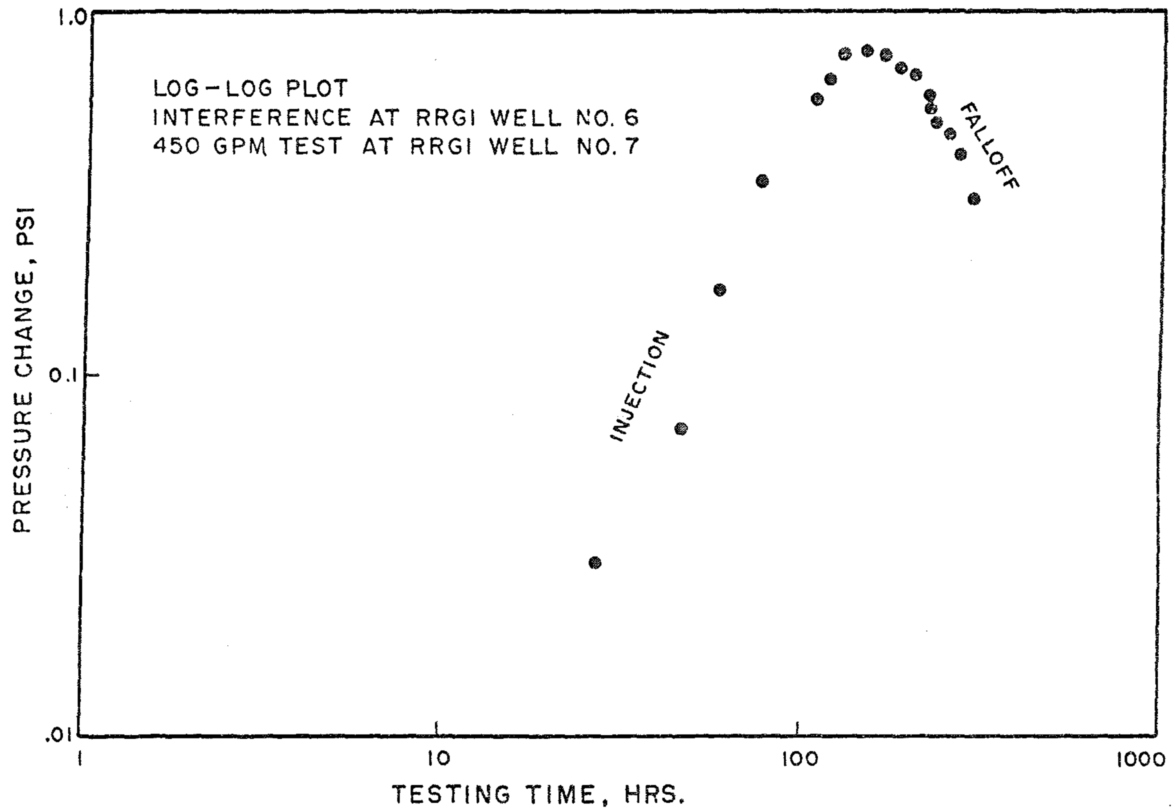

Figure 16. Log-log plot of wellhead pressure changes at RRGI-6 during injection into RRGI-7.

features help explain the high 96 md permeability calculated from the interference data. 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 is calculated as 470 md. A similar permeability value is estimated from the RRGI-6 spinner survey data.

This permeable thief zone detected at RRGI-6 did not have any effect on pressure measurements at RRGI-7. Though the thief zone is cased off at RRGI-7, had there been any direct communication (within reasonable distance from the wellbore) between the injection zone and the thief zone, a high positive skin factor should have been reflected by the pressure data due to partial penetration effect (Kazemi and Eith, 1969; Saidikowski, 1979). Careful investigation of geophysical logs by Orange (personal communication, 1979, Appendix B) indicates that there is a twenty foot zone of high resistivity 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 depth, but it is not pronounced. Details of the geophysical log evaluation is in Appendix B.

From the injectivity tests, spinner surveys and log evaluation, a picture of injection zone has been hypothesized and is illustrated in Figure 17.

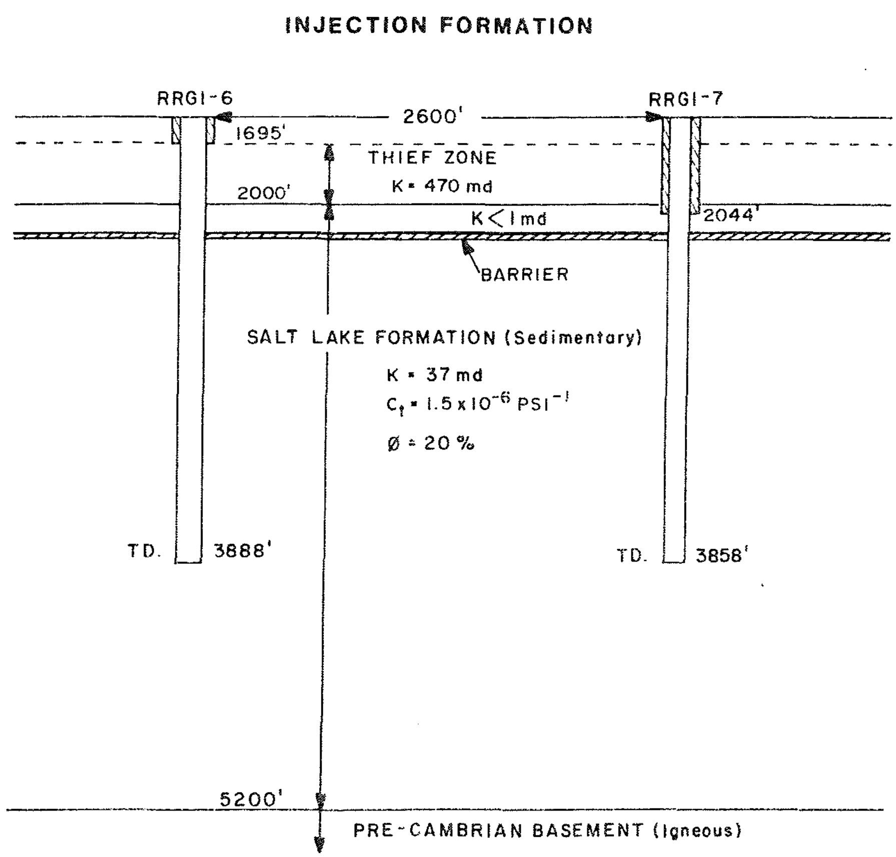

Figure 17. Composite Interpretation of Injection Zone

4. INJECTION PERFORMANCE PREDICTION

A two dimensional numerical model, RZTWO, has been used to history match the injectivity tests, simulating radial flow away from the wellbore. The grid system in cylindrical coordinates is shown in Figure 18. The model is based on pressure solutions from finite difference approximations of the flow equations and can simulate vertical sections (including gravity effects) and horizontal sections. Either an alternating diagonal or direct banded matrix inversion technique is employed to obtain solutions to the equations. Input data includes permeability, porosity, system compressibility, fluid properties and formation volume factors as functions of pressure. Permeability and porosity can be specified for individual grid blocks as well as constant rate or constant wellbore pressure. Output data include time, cumulative injection, fluid in place, pressures, and material balance errors.

Using the average reservoir properties listed in Table 1 and the hypothesized reservoir as illustrated in Figure 17, the wellhead pressure performance trend of the 450 gpm test has been matched and is illustrated in Figure 19. The good match reinforces the applicability of the reservoir properties calculated from all the transient well tests.

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

- Cased Thief Zone in RRGI-7 (the present situation with RRGI-6 open to and RRGI-7 cased to the thief thief zone).
- Well completion into the Thief Zone (perforating the RRGI -7 casing and permitting fluid flow into the thief zone).

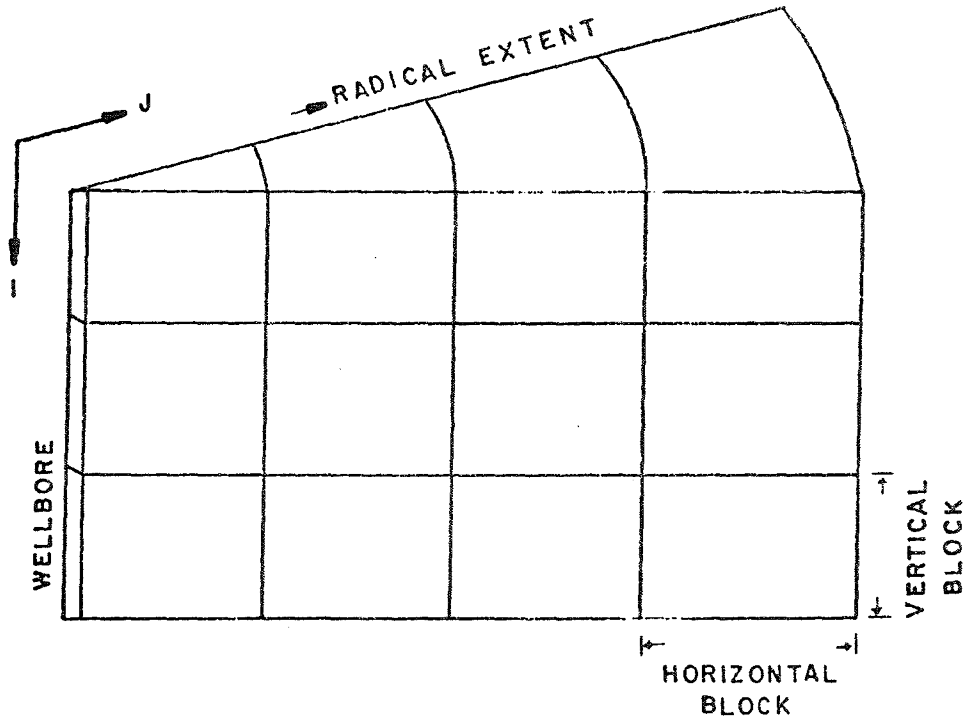

Figure 18. Radial Grid System.

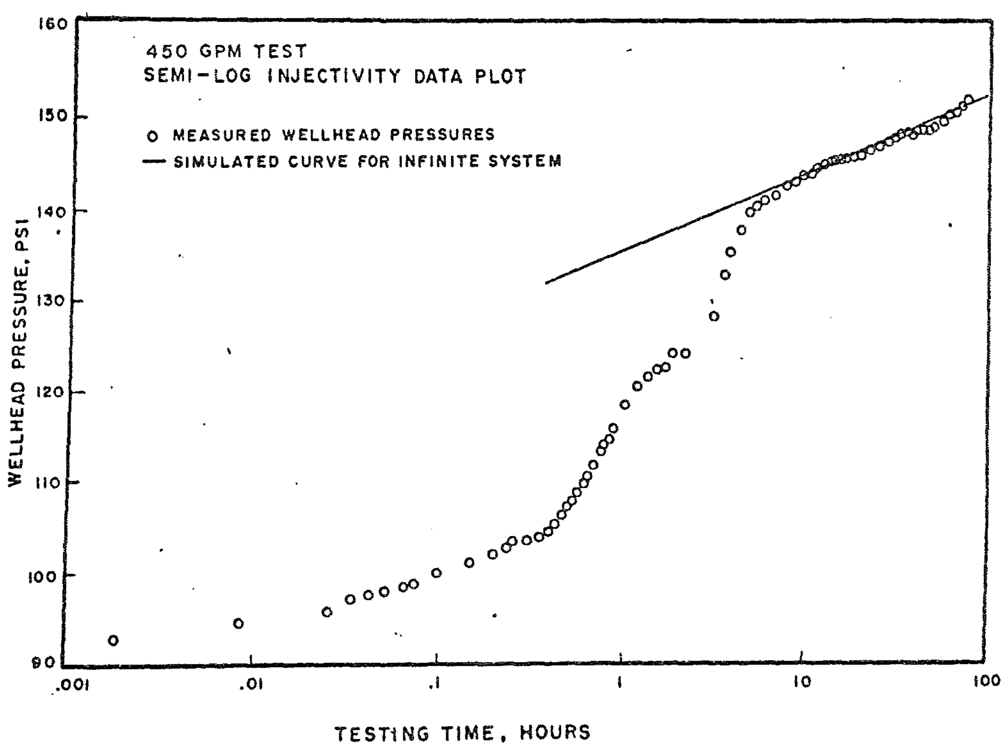

Figure 19. Comparison of wellhead pressure with results from numerical simulator.

In view of the uncertainty of the reservoir geology, several reservoir geometries have been considered.

Cased Thief Zone: Figure 20 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 in about two months. Even the presence of a possible sink 30 miles to the north at the Salt Lake Formation - Snake River Basalt boundary would not have effect at early times (prior to about four years of injection) because of its location at a great distance.

Hydraulically fracturing the Salt Lake formation in RRGI-7 has been considered to increase the injection potential of the formation to 2500 gpm. A simulation ratio of 3.5 is required to achieve the goal. From the curve of stimulation ratio versus relative conductivity, a 500 md-in/md relative conductivity is necessary for the required stimulation ratio (Figure 21). The formation permeability of 37 md necessitates a 15 darcy-ft fracture conductivity. Figure 22 illustrates the available fracture conductivity for different proppant concentrations and in-situ effective pressures. A 15 darcy-ft fracture conductivity at the required 1500 psi in-situ stress cannot be achieved irrespective of fracture width.

The effects of an additional well on the existing two wells have been studied. The numerical model was used to simulate wellhead pressure rise at the wells upon injecting 840 gpm into each well. Figure 23 illustrates the wellhead pressure with injection time at different locations for the new well. It is seen that a well drilled two miles north of RRGI-7 could possibly solve the injection problem but is dependent on the existence of a hypothetical sink twelve miles northeast RRGI-7.

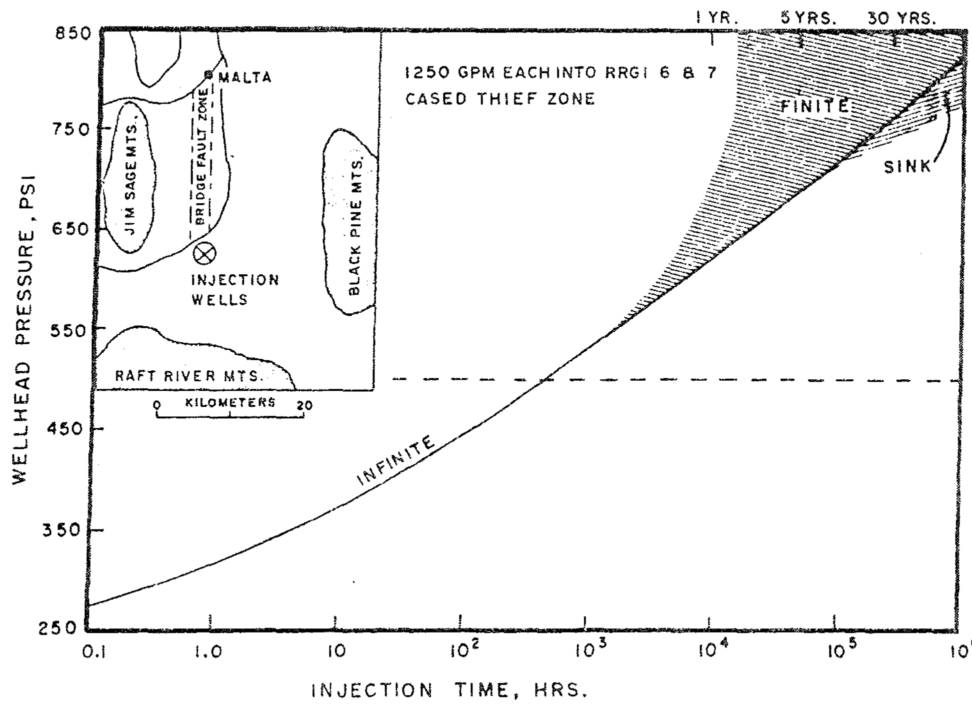

Figure 20. Simulated wellhead pressure with 1250 gpm injection into each RRGI-6 and 7 with cased thief zone.

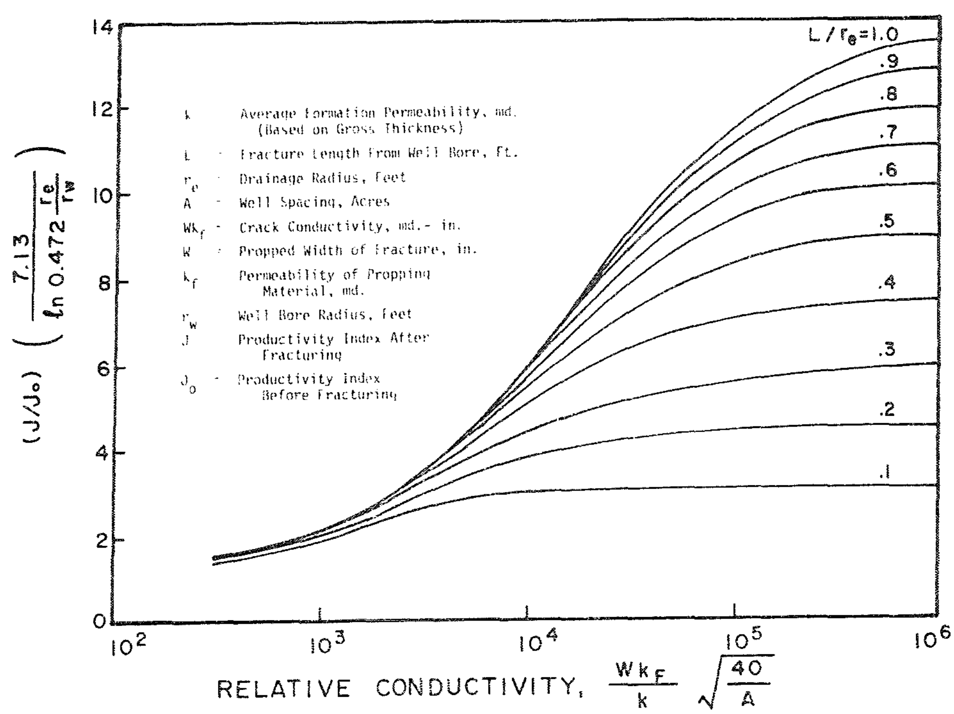

Figure 21. MHF Stimulation Ratio Versus Relative Conductivity. (From McGuire and Sikora, 1960).

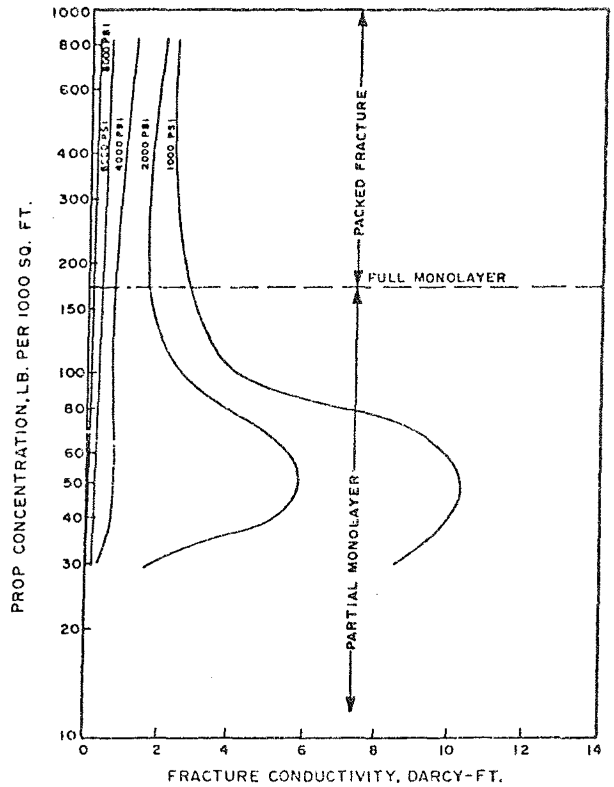

Figure 22. Proppant Concentration for Required Fracture Conductivity (From Howard & Fast, 1970).

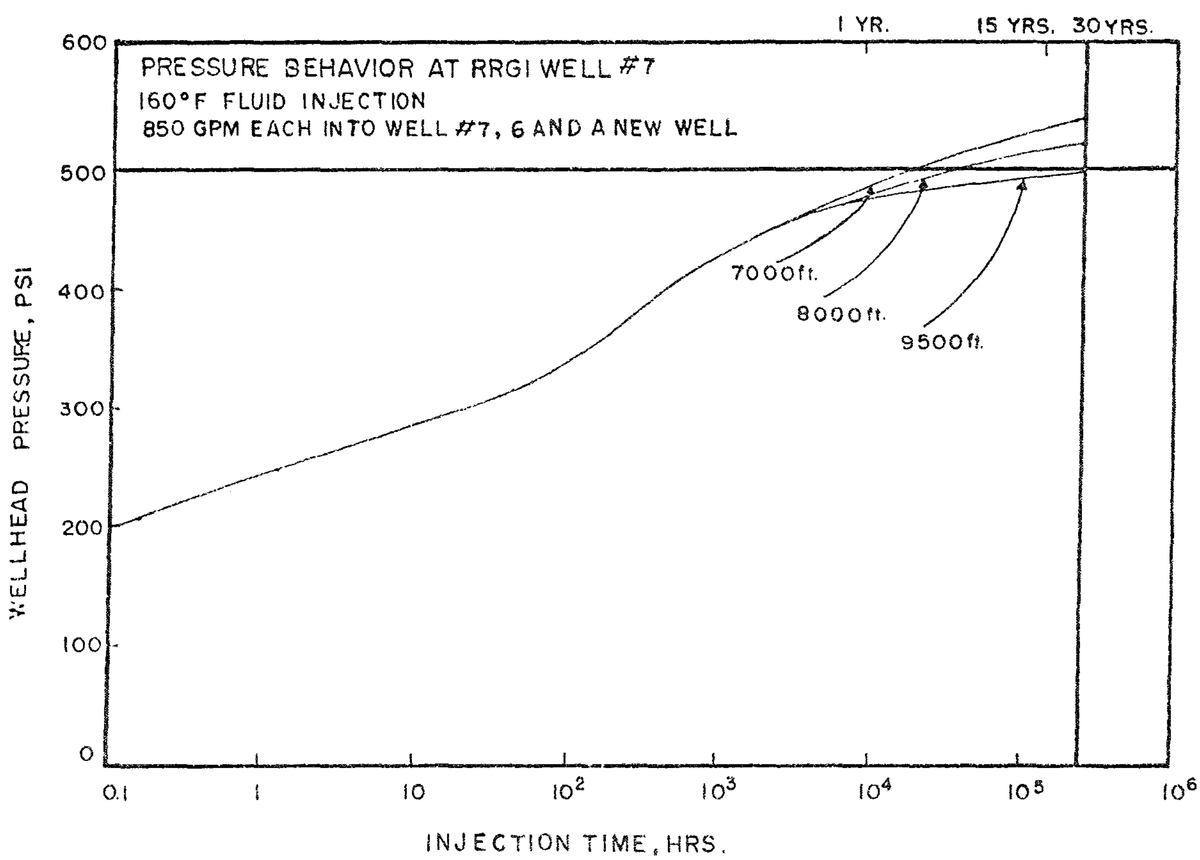

Figure 23. Wellhead Pressure versus Injection Time for Different Locations of a New Well.

Perforations into 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 lack contact with these aquifers. A numerical study has been performed to assess the pressure behavior upon completion into the thief zone. Figure 24 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 within 4 miles would cause an adverse pressure increase at earlier times, possibly within one to two years.

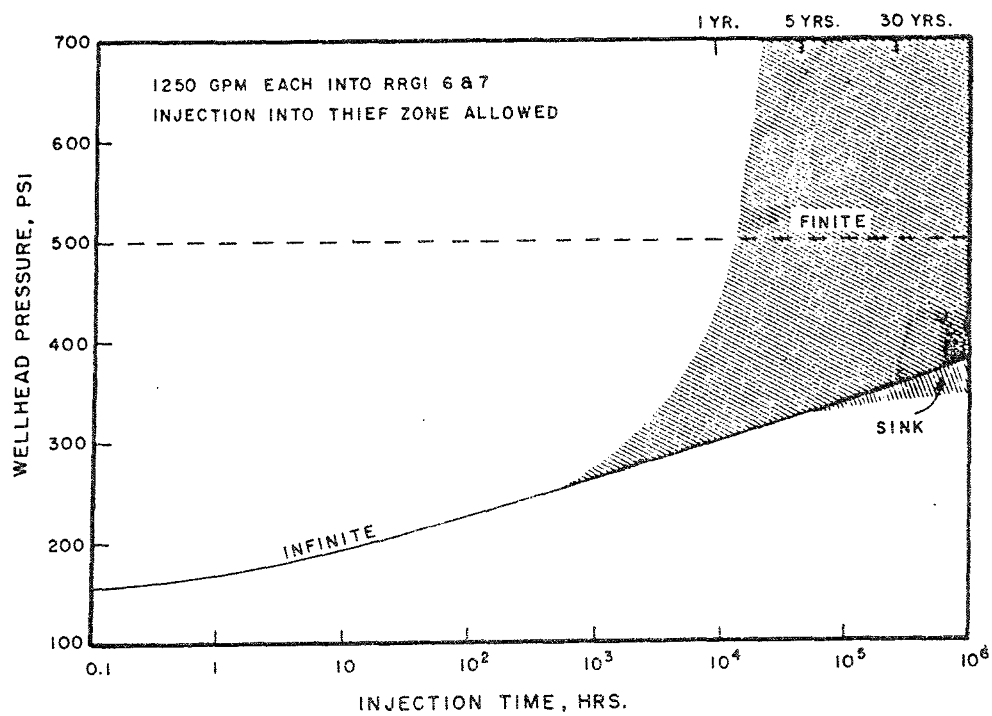

Figure 24. Simulated Wellhead Pressure with 1250 gpm Injection into Each RRGI-6 and 7 with Uncased Thief Zone

5. CONCLUSIONS

- The present well condition (RRGI-7 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 improve injectivity, and success of a new well depends on the 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 area greater than 450 square miles.

- Injecting some spent fluid into the producing horizons could help solve the injection problem, but this may introduce the chances of early thermal and/or hydrological breakthrough to the producing formation. This concept needs careful evaluation.

- 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. Therefore additional geological investigations that focus on these questions deserve support.

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 us. We also want to thank Scott Keys, Ulrich Schmischal and Richard Hodges of the U.S. Geological Survey for providing a preliminary interpretation of their spinner surveys.

This work was supported by DOE Contract No. DE-A007-77ET28301.

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APPENDIX A:

INJECTIVITY DATA ANALYSES AND

TEMPERATURE COMPENSATION, 1979 TESTS

1979 TESTS -

INJECTIVITY DATA ANALYSES AND

TEMPERATURE COMPENSATION

750 GPM Test: At initial reservoir conditions of 1677 psi pressure (3700 foot depth) and 97°C temperature, 127°C (approximately) water was injected into the well at a constant rate of 750 gpm for five and one-half hours. Figures A1 and A2 illustrate the semi-log plot of pressure and temperature rise with injection time as measured at the bottomhole and wellhead respectively. Both figures clearly indicate the effect of temperature on pressure changes. To accurately analyze the data, wellbore storage and temperature effects need to be determined. Figure A3 is the log-log plot of pressure versus time for both the bottomhole and wellhead conditions. It is seen that wellbore storage effects cease after about 0.03 hours and the formation has a 1.47×10^{-6} psi^{-1} system compressibility. Therefore, the correct semi-log straight line can be drawn in Figures A1 and A2 after 0.03 hours, provided the temperature effect is minimal. For example, in Figure A1 a semi-log straight line is drawn between times 0.03 hour and 0.1 hour during which the temperature remains fairly constant around 97°C. After 0.1 hour, temperature rises sharply and so does the pressure. From the correct semi-log straight line the average permeability of the 1814 feet open hole is calculated as 38 md. A similar analysis of the wellhead measurements shown in Figure A2 results in a 37 md permeability. In both cases, the skin factor remained close to zero.

Rather than finding a region in the semi-steady state period beyond which wellbore storage effects are not influenced by temperature changes, an attempt has been made to compensate the wellhead pressures for temperature effects. The principal effect is the density difference in the column of the water

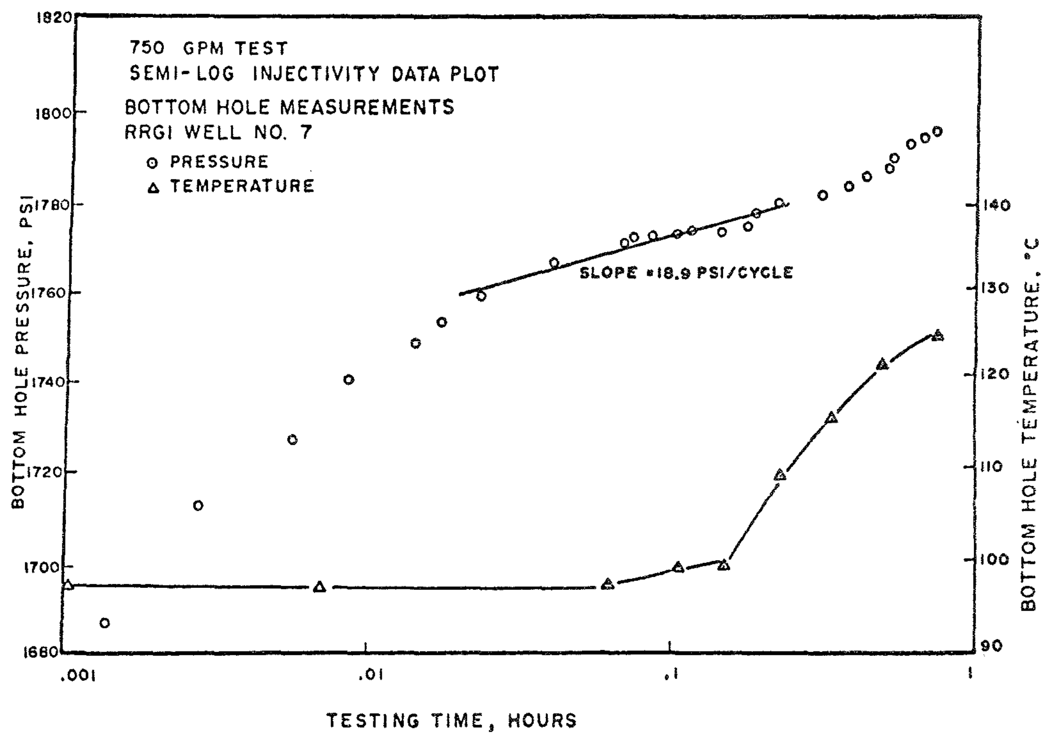

FIGURE A1. Semi-log plot of downhole pressure and temperature, 750 gpm injection.

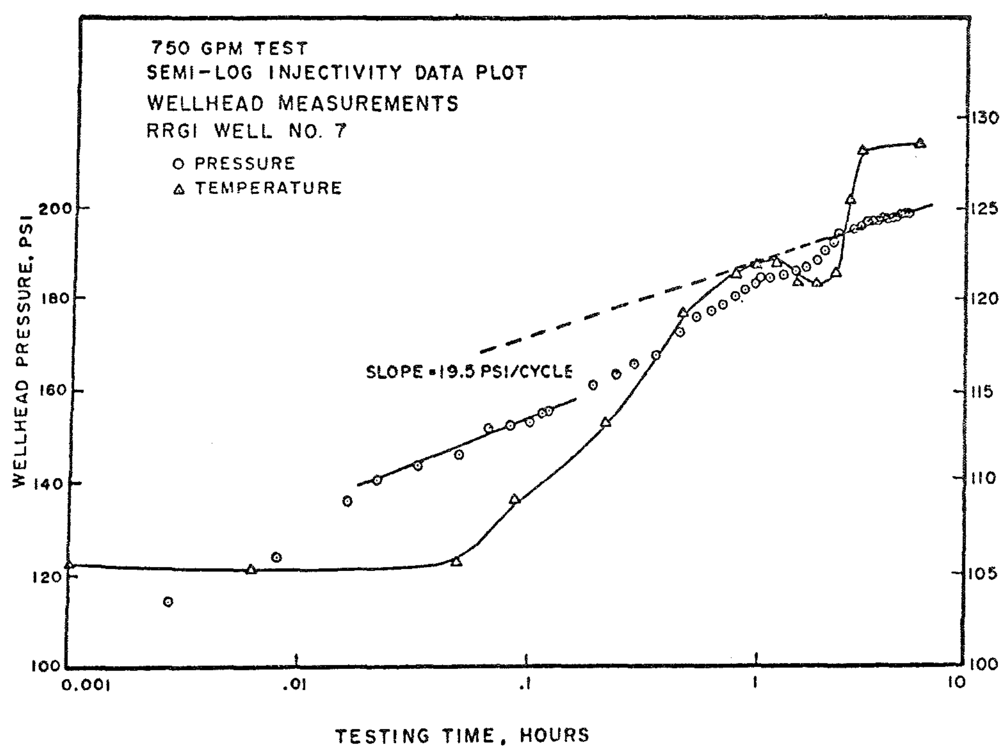

FIGURE A2. Semi-log plot of wellhead pressure and temperature, 750 gpm injection.

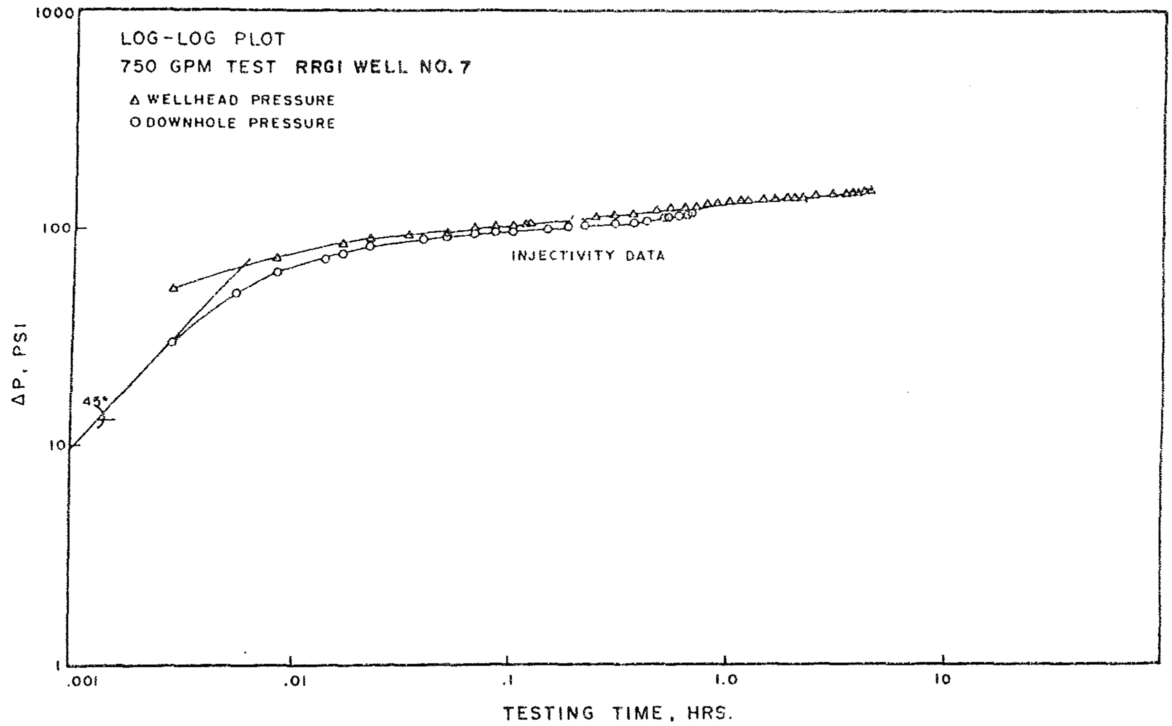

Figure A3. Log-log plot of pressure change versus time, 750 gpm injection

caused by thermal expansion. Figure A4 is a plot of both the wellhead and bottomhole temperature variation with time. To simplify the analysis, an average temperature curve has been drawn. This temperature curve has been used to compensate the wellhead pressures by deducting or adding pressures from the actual data by values corresponding to temperature differentials using 102°C as the initial temperature. Figure A5 illustrates the temperature compensated pressure data and from the semi-log straight line of temperature pressure data, permeability is calculated as 37 md and a skin factor as zero. The reservoir properties presented encompass a 1400 foot raduis of investigation.

Though the different injectivity data analyses present similar results, they should be used to complement the results of falloff data analyses. The assumptions introduced in the injectivity data analyses and the simplified

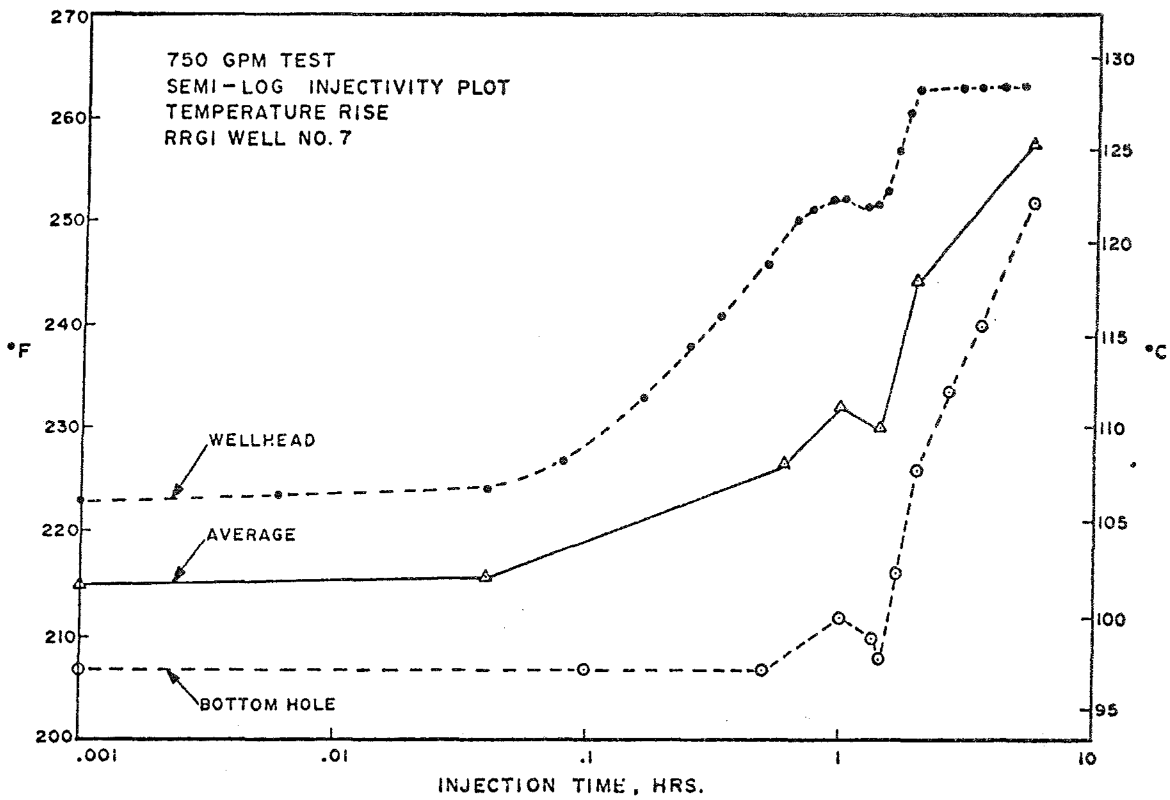

FIGURE A4. Wellhead and downhole temperature variations with time, 750 gpm injection.

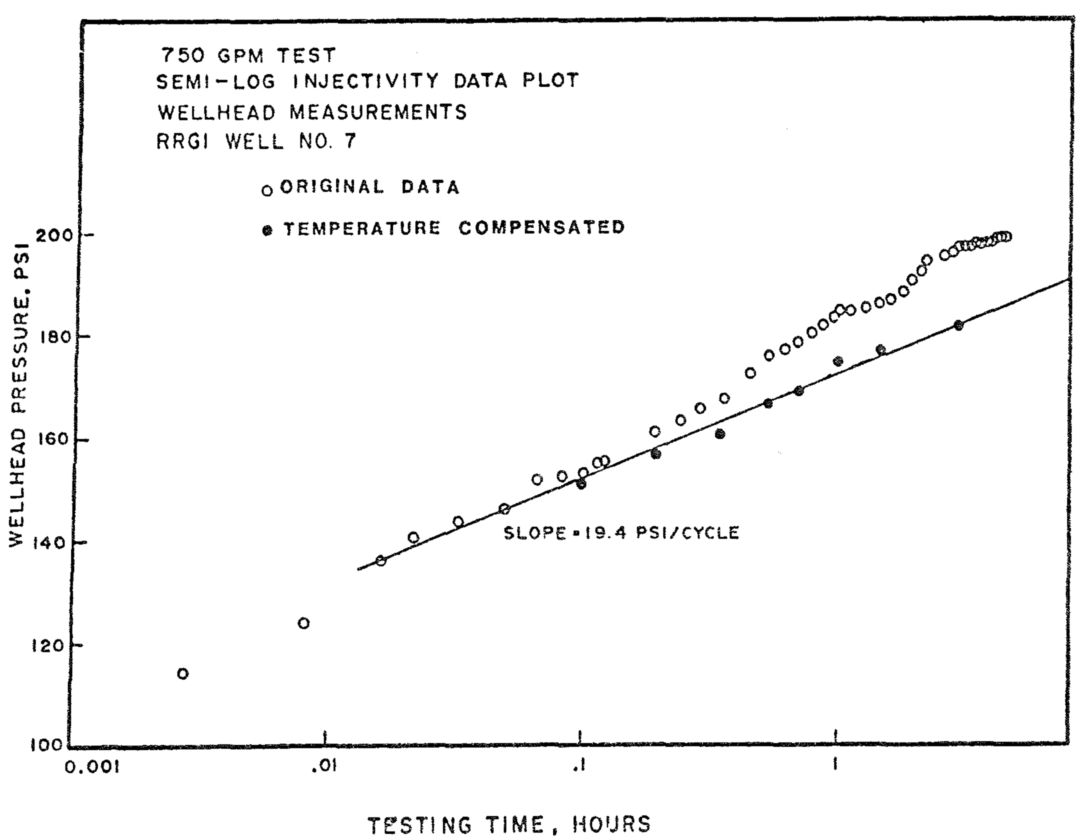

FIGURE A5. Temperature compensated pressure data.

temperature compensation method used could very well be beyond the precision required in transient pressure analyses.

620 GPM Test: At reservoir conditions of 1676 psi pressure (3700 ft. depth) and 110°C, water of 130°C was injected into the well at a constant rate of 620 gpm for eight hours. Figures A6 and A7 illustrate the semi-log plot of pressure and temperature rise with injection time as measured at the bottom-hole and wellhead respectively. The erratic behavior of the bottomhole pressure is largely due to the inaccuracy of the downhole probe (the probe fails to compensate the temperature effect on pressure when temperature changes occur at a rate greater than 1°C/minute). Figure A8 is the log-log plot of pressure versus time at the wellhead. It is apparent that wellbore storage effects

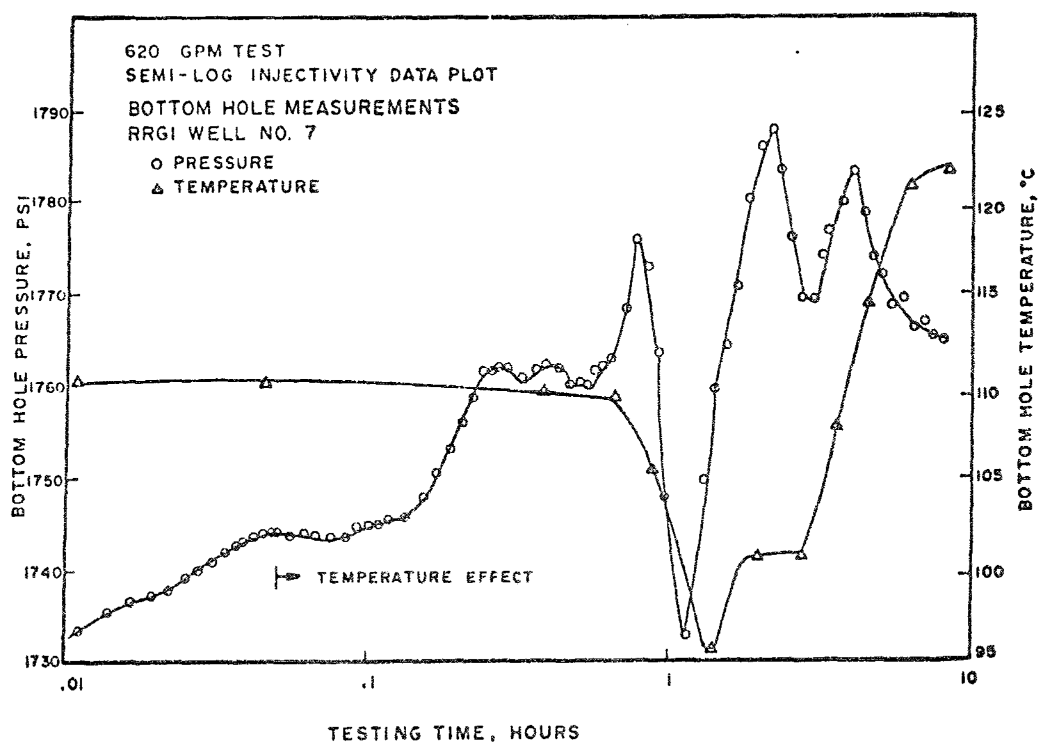

Figure A6. Semi-log plot of downhole pressure and temperature, 620 gpm injection.

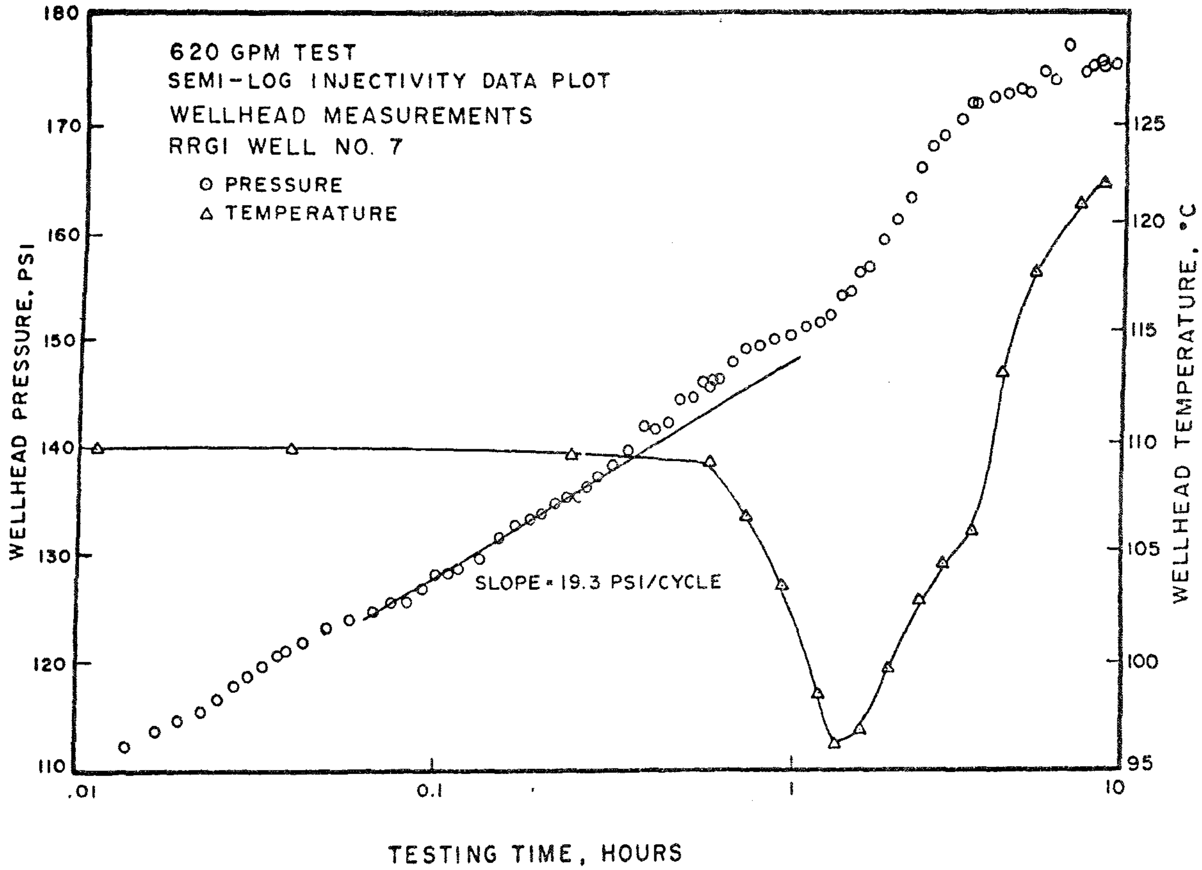

Figure A7. Semi-log plot of wellhead pressure and temperature, 620 gpm injection.

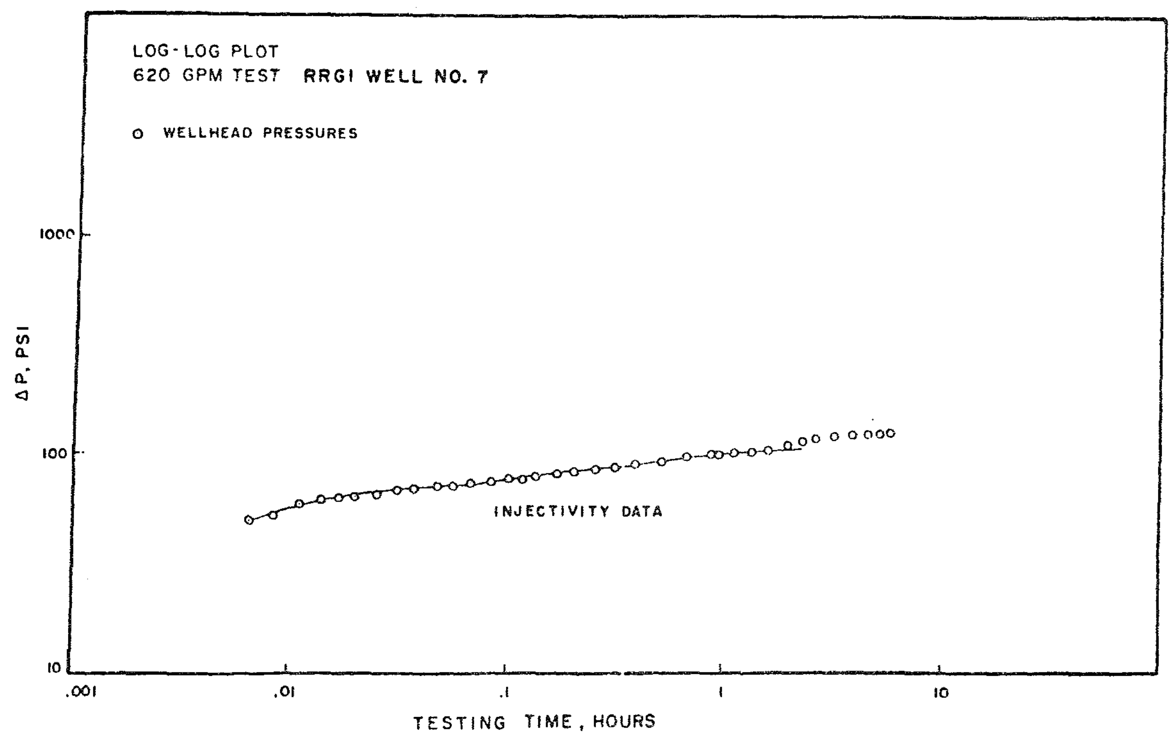

Figure A8. Log-log plot of pressure change versus time, 620 gpm injection cease after about 0.03 hours and the total system compressibility is calculated as 1.5 X 10^{-6} psi^{-1}. Choosing the correct semi-log straight line in Figure A7 (beyond 0.03 hours and over a region where temperature is constant) results in an average permeability of 31 md and a positive 0.8 skin factor.

Temperature compensation for the data was also performed on the wellhead pressure with a resultant permeability of 35 md and a zero skin factor. The reservoir properties presented encompass a 1700 ft. radius of investigation.

450 GPM Test: At reservoir conditions of 1622 psi pressure (3700 ft. depth) and 112°C, 129°C water was injected into the well at a constant rate of 450 gpm for ninety-six hours. Figures A9 and A10 illustrate the semi-log plot of pressure and temperature rise with injection time as measured at downhole and at the wellhead respectively. As seen previously, temperature has a

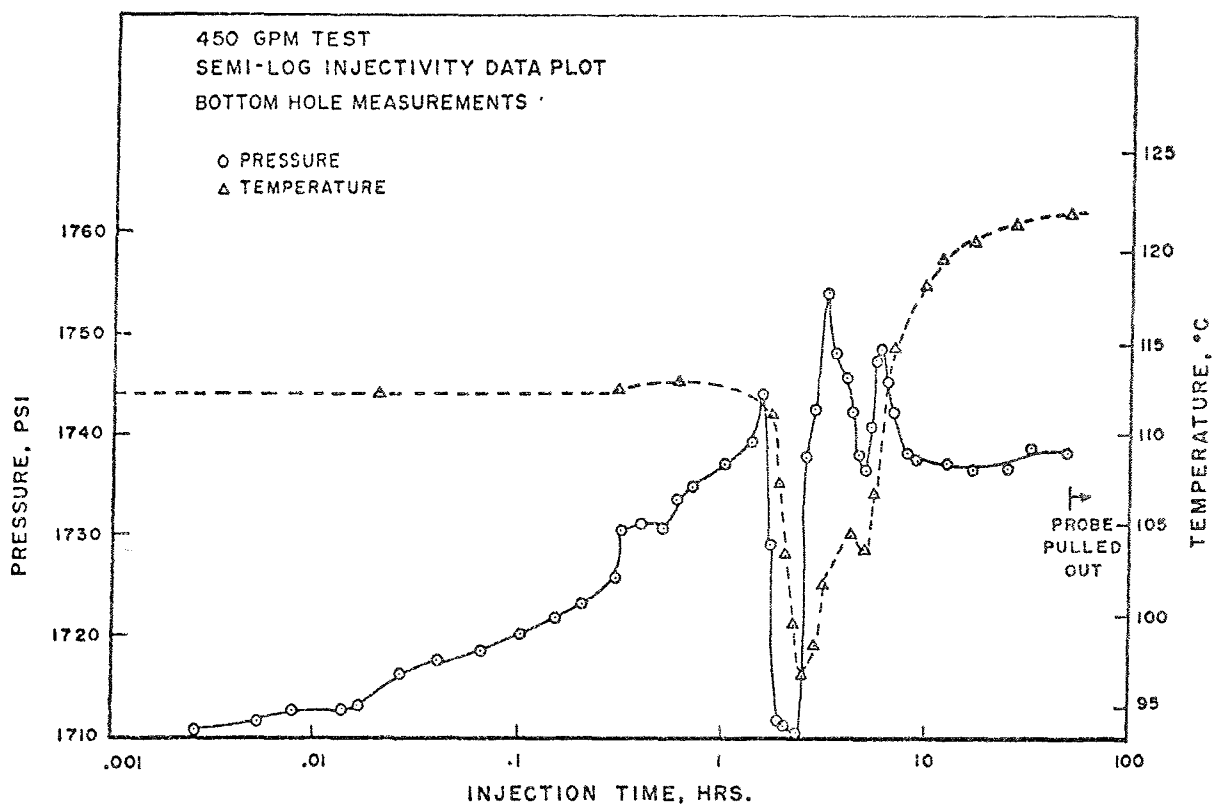

Figure A9. Semi-log plot of downhole pressure and temperature, 450 gpm injection

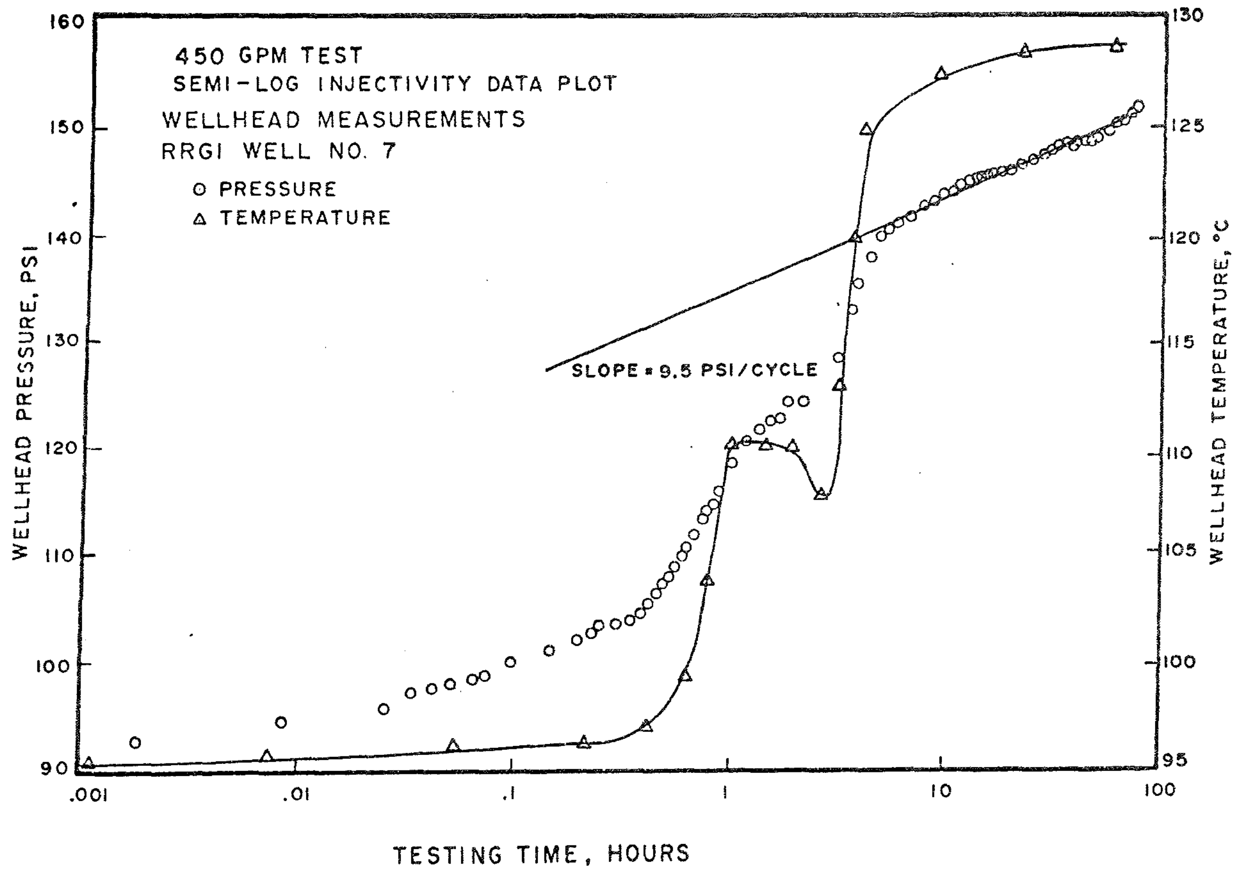

Figure A10. Semi-log plot of wellhead pressure and temperature, 450 gpm injection.

significant effect on the pressure. The bottomhole pressure variation due to temperature changes is well defined in Figure A9. From the log-log plot of pressure versus time for the wellhead data, the wellbore storage effect (including temperature effect) ceased after five hours and the total system compressiblity is calculated as 1.55 X 10^{-6} psi $^{-1}$. The correct semi-log straight line in Figure A10 (beyond five hours and over the region where temperature is constant) results in a permeability 40 md and a zero skin factor.

Temperature compensation for all the wellhead pressure data resulted in a permeability of 40 md with a negligible positive skin factor. The reservoir properties presented encompasses a 5800 ft. radius of investigation.

APPENDIX B:

GEOPHYSICAL LOG EVALUATION

TELEPHONE: (512) 345-5342

ARNOLD S. ORANGE
4200 BURNEY DRIVE
AUSTIN, TEXAS 78731

October 1, 1979

Dr. Kenneth Wolgemuth
Terra Tek, Inc.
University Research Park
420 Wakara Way
Salt Lake City, Utah 84108

Dear Ken:

The following is a summary of my thoughts regarding the Raft River, Idaho injection well project. The first series of comments concern the study of the suite of down-hole logs for injections wells #6 and #7.

1. The logs are of high quality and provide a valid basis for the study of the properties of the formations under consideration.

2. Production is from fractures, thus the implication is that injection should be into fractures to handle the volumes of water involved. Primary goal of the log study was to attempt to locate fracture on potential fracture zones. A secondary goal was to identify low permeability seals within the Salt Lake formation.

3. The "spinner" indicates relatively uniform absorbtion of fluids by #6 and #7, with exception of the "thief" zone in #6. The logs are also relatively uniform, including the "thief" zone.

4. The Salt Lake Formation is generally porous, conductive, and with a relatively slow acoustic velocity. The formation may be broadly divided into two zones as indicated on the conductivity log (deep induction tool). The upper zone to a depth of about 2600' in #6, 2700' in #7 containing more variations and conductive kicks or spikes, than the more uniform lower zone. In #6, the upper zone includes, but is not confined to, the "thief" zone. Correlation of the conductivity logs for wells 6 and 7 for this feature is excellent.

5. Since below the surface casing wells were drilled with what was essentially formation water, the E logs are poor indicators of isolated, limited thickness fractures or fracture zones. The acoustic logs have a generally noisy background, but are useful in confirming the presence of tighter, denser members.

6. The anomaly in the logs in #7 at 2750'-2900' is considered to be hole effect, due to the considerable increase in hole diameter through this zone. This does not imply that this zone is not anomalous, in fact the cause of the washout should be a topic for investigation. It just says that the logs appear to be reacting to the diameter change and not the root cause of that change.

7. The anomaly in #7 at 2450'-2490' (marked A) may be a tighter unit accompanied by fractures at the base. The tight unit is indicated by higher resistivity and velocity in the interval, and the relative uniformity. The fractures are suggested by the conductive spike(s) on the resistivity log, possibly supported by low velocity points on the velocity log. This zone could warrant a closer look, both as a seal (tight unit) and zone for fracture stimulation (conductive "spikes"). Immediately below the tight zone the logged resistivity approaches the resistivity of the formation water, which suggests fracture porosity in addition to formation porosity. This anomaly may correlate with a weaker resistive anomaly (A') in #6 at a depth of 2480'. These may be correlative members but the evidence is weak. Looking at the detail resistivity log (expanded depth scale), trace separation (between the three tools) for the conductive "spike" at the base of the resistive unit may indicate fracture invasion or just be an indication of the extreme thickness of the "fracture" zone. Further study of this anomaly is recommended.

8. There is a possible conductive anomaly in #7 at 2260'-2290' (marked B). This could be a poorly cemented, coarse grained member. No anomaly is evident in #6 to correlate with B.

9. There is a weak resistivity high on #6 at 1900' (C) that may correlate with a similar feature (C') on #7 at 2150'.

10. The study points out the need for coring whenever possible. Even if recovery is poor, what core is obtained will go a long way towards understanding the subtle variations observed in the logs.

11. If the objective is locating and identifying fractures, consideration should be given to using salt gel while drilling at depth. Microlateralog and short spacing induction logging devices could then be used to good advantage in detecting the invasion of smaller fractures by the conductive mud filtrate.

General considerations - The following are comments pertaining to the general question of locating and identifying subsurface zones favorable for injection purposes.

1. The detection of thin, discontinuous members at depth from the surface is extremely difficult. If the placement of the members is structurally controlled (i.e., in the lows on an old erosional surface) detailed gravity or magnetics would be a remote possibility. If structure is not present, then the geophysical options are limited to reflection seismic.

2. High resolution reflection seismic is potentially capable of detecting the reflection from a thin member. However, in the case under consideration, (a) the acoustic impedance (velocity) contrast is relatively low as indicated in the acoustic logs examined which will lead to low amplitude reflections; (b) these will be spurious reflections from other, similar velocity contrasts within the section, and (c) a near surface section consisting of alluvium and interbedded volcanics almost invariably lead to poor quality seismic records. The cost of a meximum effort multi-trace seismic survey will cost between $5-10,000/per mile for data acquisition and processing. This might however, be a fit topic of study for a U.S.G.S. research seismic crew.

3. If the injection wells #6 and #7 are the only options, then the section above the casing offers a known injection capability. Deepening the hole may lead to the intersection of adequate fracture permeability, but even though this must, based on well #3, be a high probability, it is by no means assured. The Salt Lake formation remains probably the poorest in the section from an injection standpoint, considering the thickness of rocks in the formation.

4. If an additional well(s) is under consideration, strong emphasis should be placed on placement on geologic grounds. In particular, the "narrows" zone should be investigated as a zone of possible increased joint permeability. Movement to the west should place a well closer to ~~an~~ (or) across the Bridge Fault zone, with its attendant fracture permeability.

I hope that the above helps in your preparation of the report. I have enjoyed working with you on this project and am looking forward to our continuing association.

Sincerely,

Arnold Orange

AO:jl

APPENDIX C

INJECTION CAPABILITY AT THE

RAFT RIVER GEOTHERMAL SITE

Paper presented at the Fifth Annual Workshop on Geothermal Reservoir Engineering, Stanford University, December 12-14, 1979.

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.

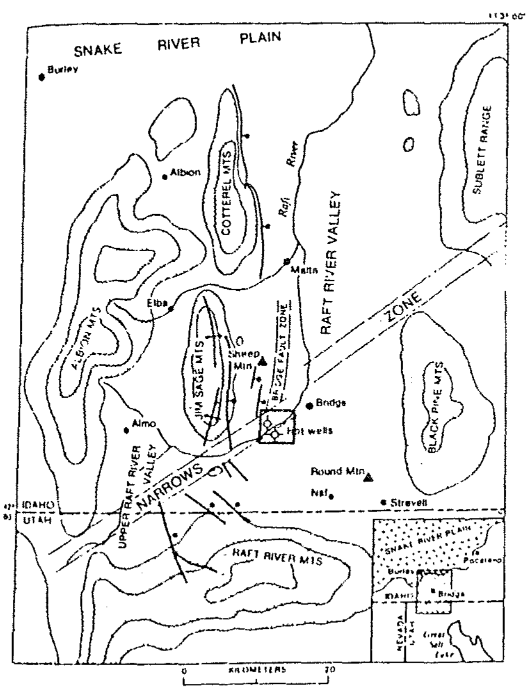

FIGURE 1. Map of the Raft River Valley Area.[6]

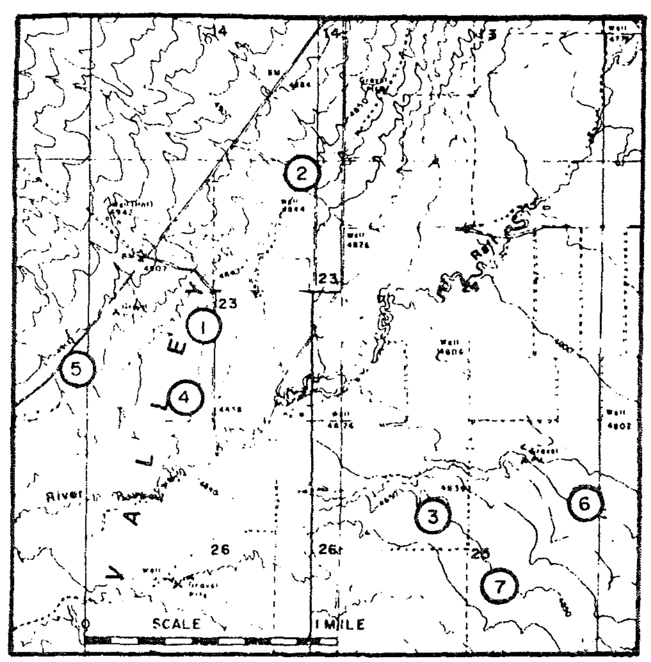

FIGURE 2. Raft River Geothermal Site Well Location (enlarged square section of Figure 1.)

* Paper presented at the Fifth Annual Workshop on Geothermal Reservoir Engineering, Stanford University, December 12 through 14, 1979.

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

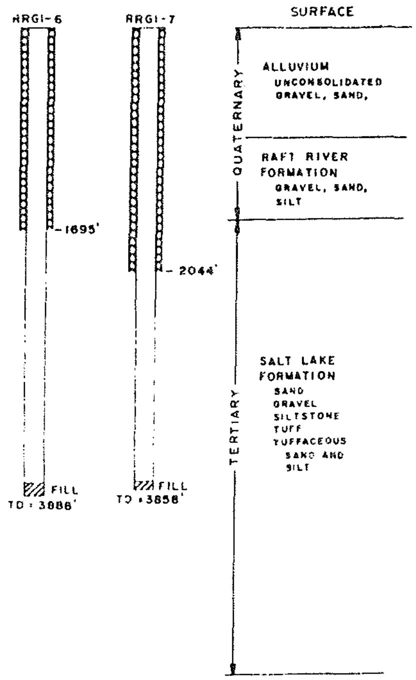

FIGURE 3. Stratigraphy of RRGI-6 and 7.

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 x 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 x 10^{-6} psi^{-1}, and the well indicates negligible skin factor (-0.3).

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.

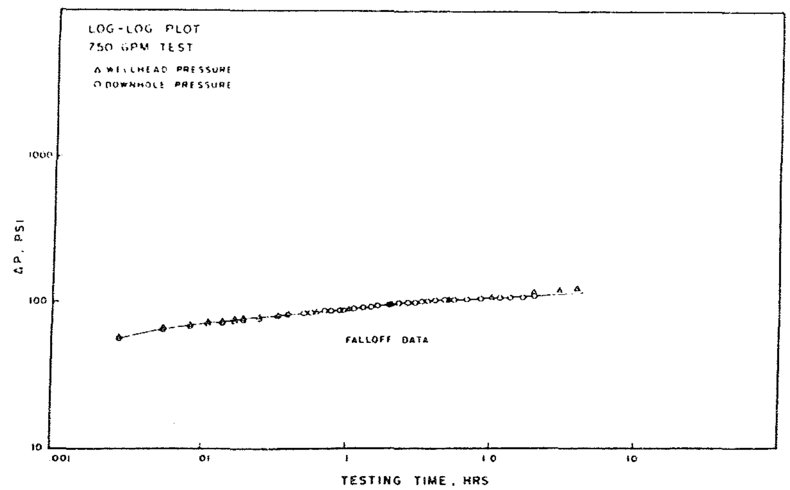

FIGURE 4. Pressure Change Versus Time.
750 GPM Falloff Data.

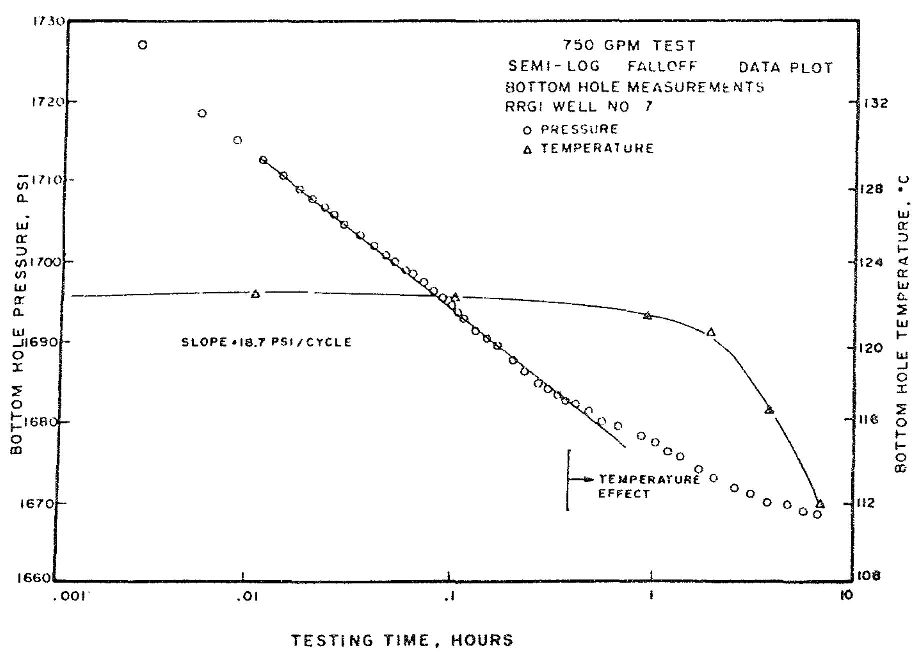

FIGURE 5. 750 GPM Bottom Hole Falloff Data.

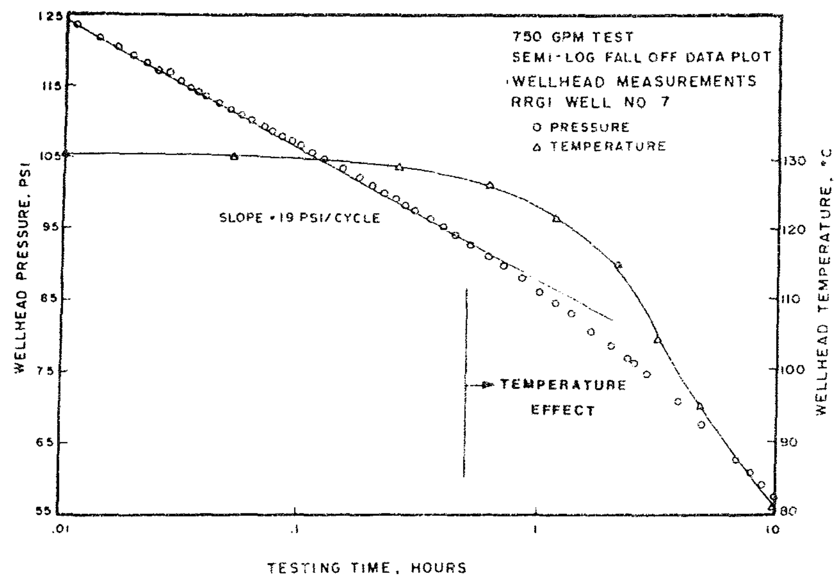

FIGURE 6.   750 GPM Wellhead Falloff Data.

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.

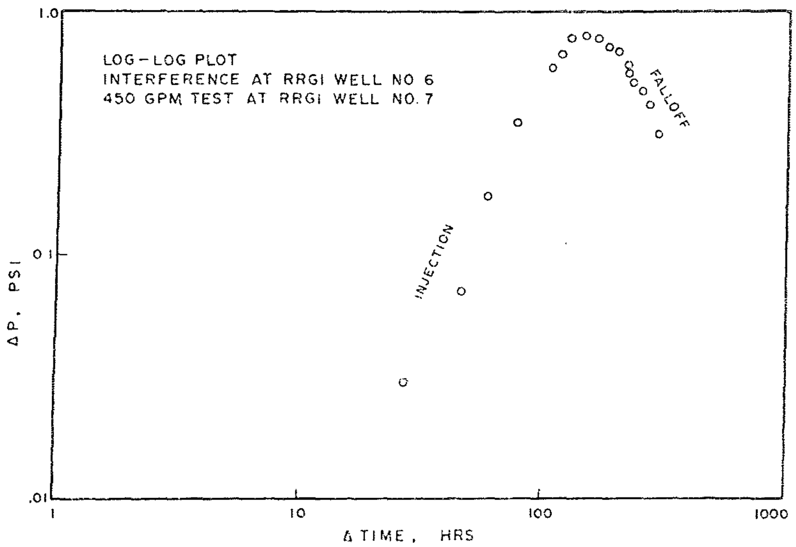

FIGURE 7. Interference Pressure Change Variation at RRGI-6.

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.

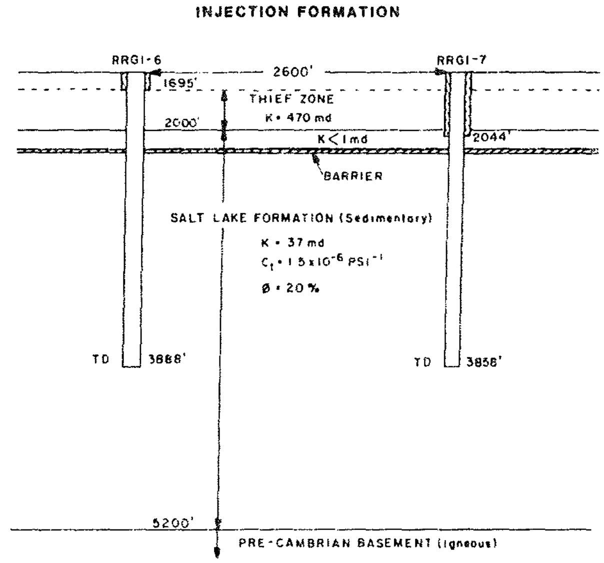

FIGURE 8. Hypothesized Injection Formation.

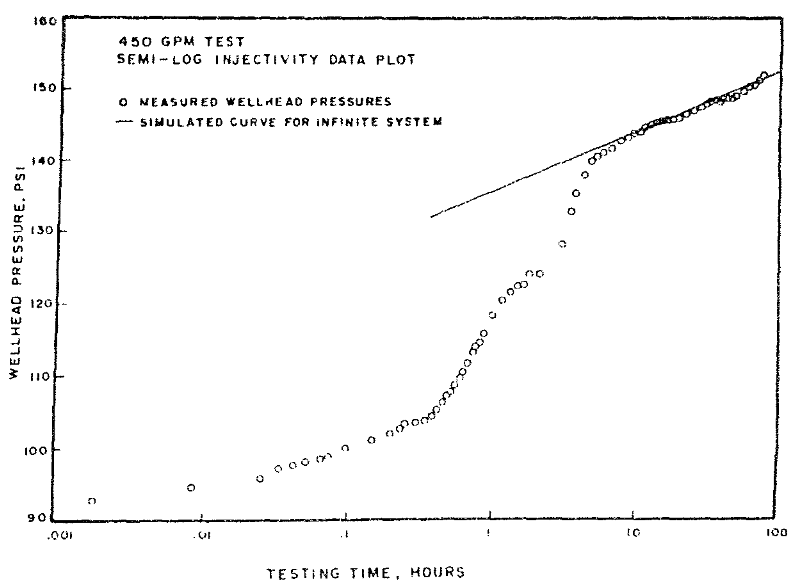

FIGURE 9. History Matching of RRGI-7 450 GPM Injection Test.

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.

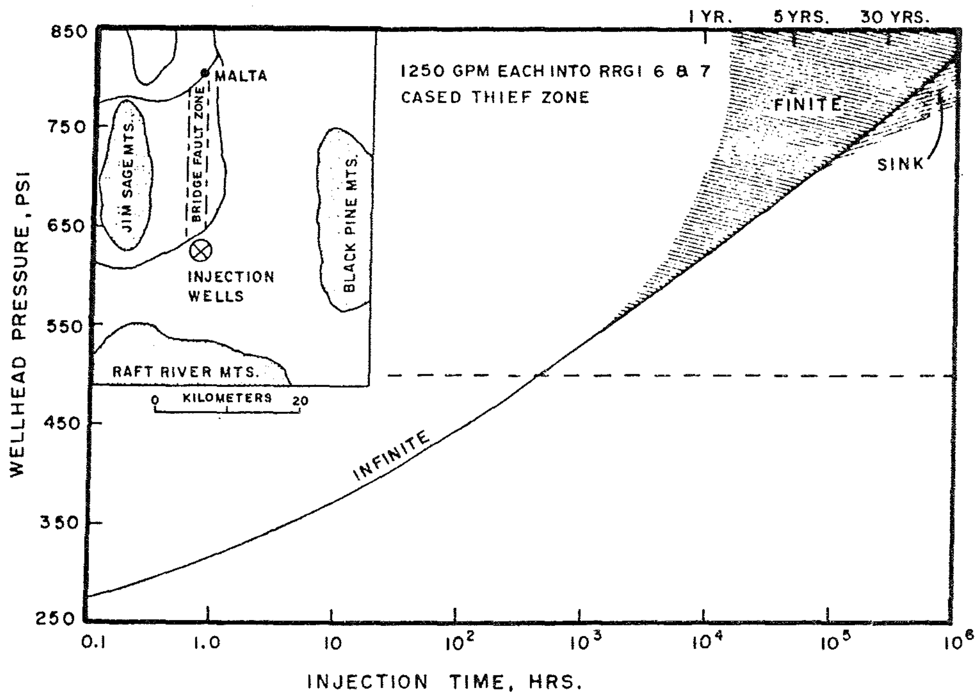

FIGURE 10. Cased Thief Zone.

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.

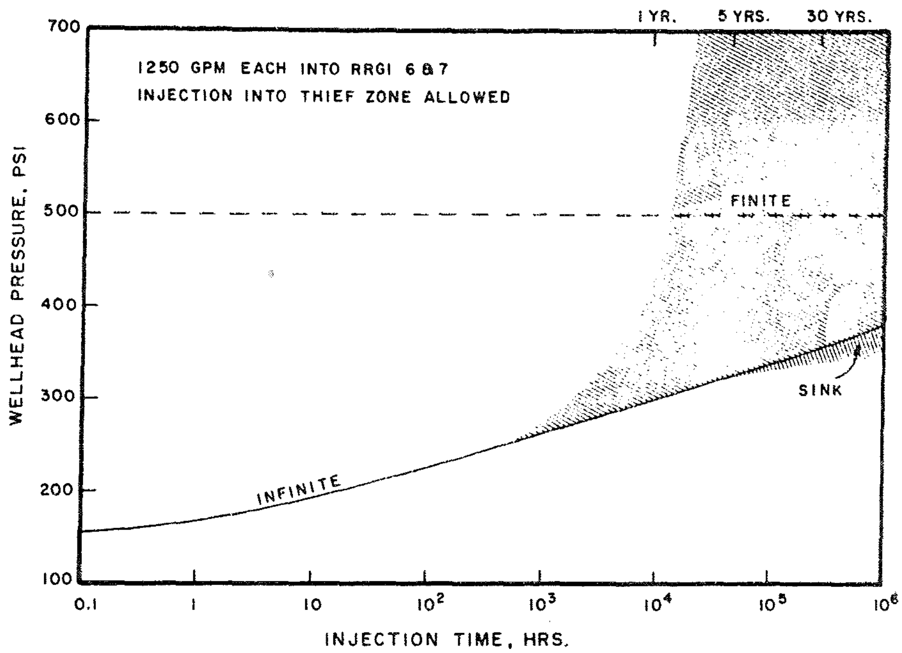

FIGURE 11. Uncased Thief Zone.

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.

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AUG 2 2 1980

Martin R. Scheve
DOE-HQ

Original Signed by
John L. Griffith
DOE-ID

INJECTION CAPABILITY AT RAFT RIVER

Over the past several months there has been a continuing dialogue involving DOE-HQ, DOE-ID, EG&G Idaho, and the State of Idaho on the subject of injecting geothermal fluid at Raft River. The attached information addresses the current injection capability and provides some additional information about the options which are available to DOE. The attachments include a discussion of the latest concerns which have been expressed by the State of Idaho relative to the EPA and Idaho injection regulations, and a summary table which lists the conditions and estimated costs of these options.

The attachments presented were prepared by this office and by EG&G Idaho. Hopefully, we have included enough information that you can draw your own conclusions. The perforation of casings of existing wells is not considered a viable option. The reason for this conclusion is discussed in detail in Attachment No. 1 to this letter. The three options considered to be acceptable are listed as shallow, intermediate, and deep injection. This office recommends drilling a shallow experimental injection well (No. 8) as discussed in the letter to Mr. DiBona, dated July 31, 1980. It is recognized that if this proves to be a satisfactory solution, two additional shallow wells (No. 9 and No. 10) would be required to provide adequate injection capability. The conditions for shallow injections are listed and the total installation cost is estimated at $1.1M of which $350K would be for the experimental shallow injection Well No. 8.

In the event that shallow injection proves unsatisfactory and long term injection at high pressures into Well No. 7 is acceptable, Well No. 6 could be converted to an intermediate injection well and a new injection well drilled. This situation is outlined as the intermediate injection system and estimated to cost $1,500,000. The deep injection well system involves deepening both No. 6 and No. 7 and drilling a new deep injection well. The total installation cost of the depp system is estimated at $2,600,000.

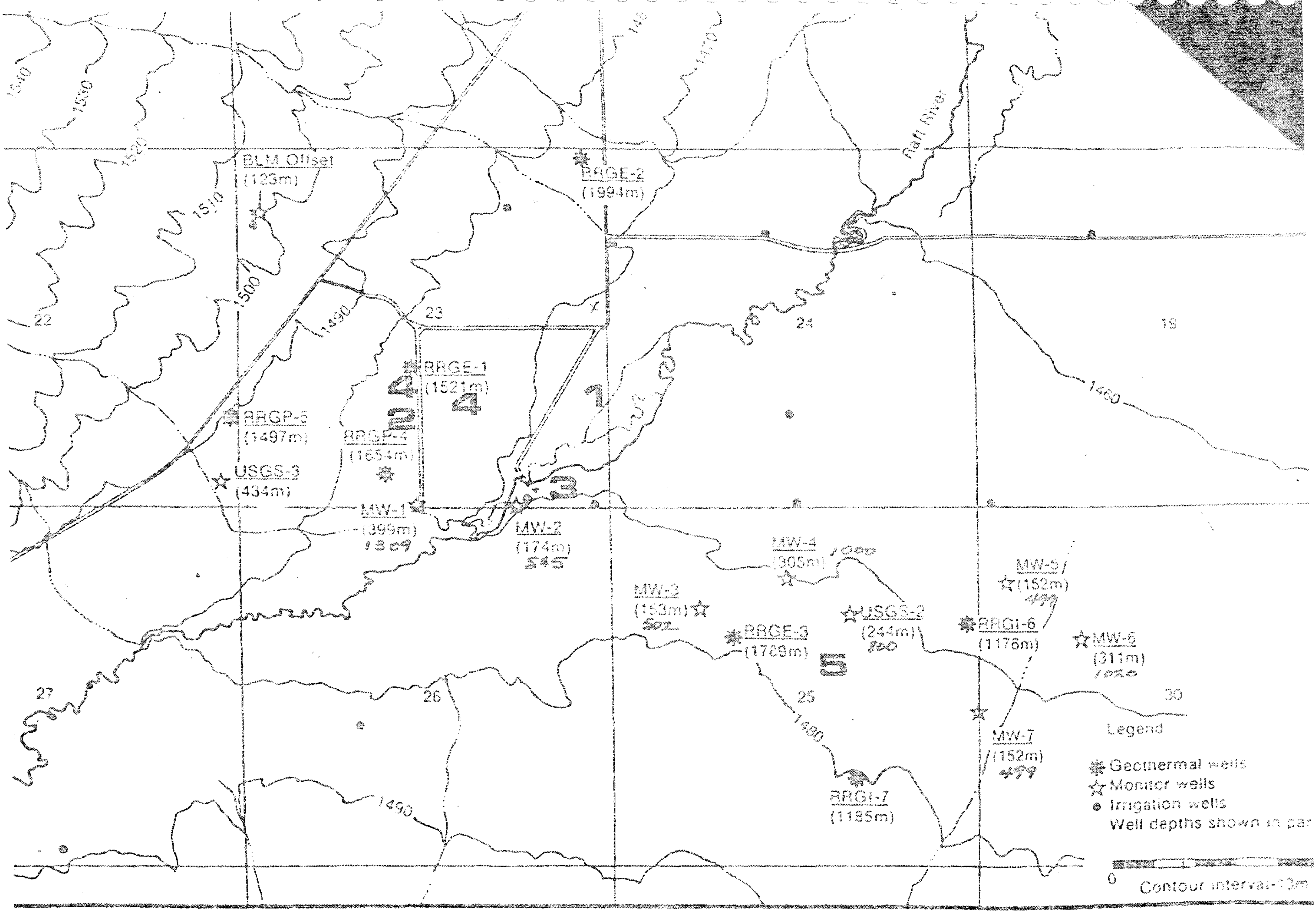

Fig. 1 Possible Locations of MW-6

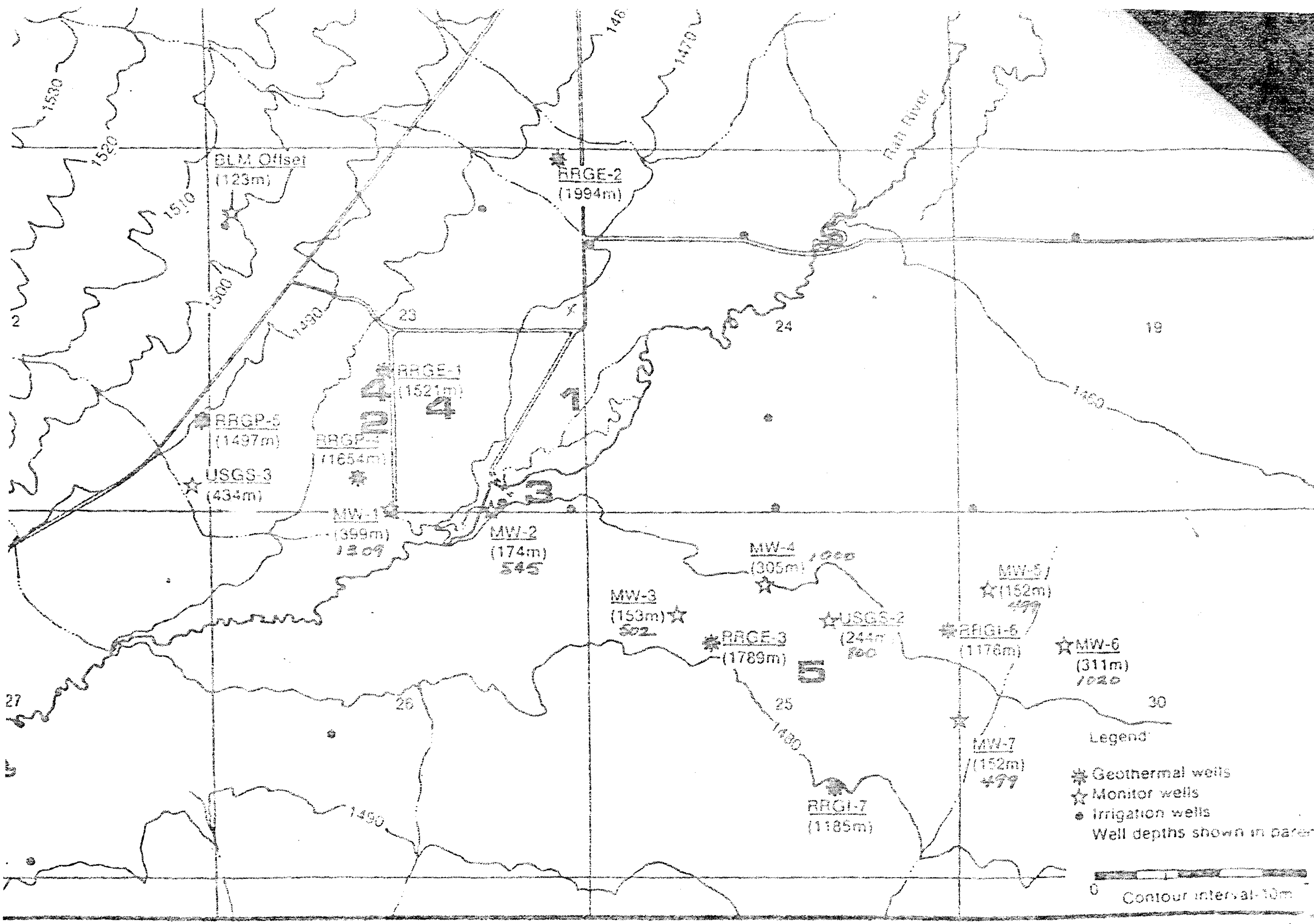

Fig. 1 Possible Locations of MW-8

Well No. 4 has not been considered in these discussions because the well has not been tested following the stimulation program. This well may be suitable to use or modify for intermediate or deep injection, but a test program would be required prior to making that determination.

If you have any questions or comments relative to this subject, please feel free to discuss them with Wayne Knowles or Roy Mink. Our current travel plans call for both Wayne and Roy to be in Salt Lake City for the GRC Meeting and in Washington during the last half of September, which might be helpful in discussing this problem and possible solutions.

cc: Jack Salisbury

Attachments:

1. Injection of Geothermal Fluids at Raft River - A Summary
2. Table of Injection Options

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INJECTION OF GEOTHERMAL FLUIDS AT RAFT RIVER

-A SUMMARY-

There is no environmentally acceptable way to dispose of the power plant fluid into RRGI-6 at the presently planned pressures and flow rates. Technically, all the water from the power plant during the first year of operation can be injected into the two existing wells. However, communication between RRGI-6 and the upper aquifers along fractures makes this not acceptable environmentally. If low pressure injection into 6 is permitted, an additional 800 gpm disposal capability will be required to operate the plant at full power

The potentially viable options are as follows:

1. Down gradient from the production wells;

2. Intermediate depth (2000-3000 ft.) injection wells south and southwest of RRGI-7; and

3. Deep (~5000 ft.) injection at high pressure away from the production wells.

The most reasonable option for disposal of this fluid is injection at line pressure from the power plant (90 psi) into the high permeability thief zone. If this option is environmentally acceptable and complies with State and Federal regulations, 2 to 3 additional shallow wells would be needed to dispose of the total fluid from the power plant. To test this concept, it would be necessary to drill a shallow injection well in an area which is unlikely to be highly fractured. Perforation of existing wells will not adequately test the capacity of a thief zone well or the environmental impacts of the injection due to unsuitable well locations and construction.

The actions proposed for testing of the low pressure thief zone injection concept are:

1. Long-term (10-30 days) testing of RRGI-7 at high pressure (300-400 psi).

2. Long-term (10-30 days) testing of RRGI-6 at low pressures (90-125 psi), which can be scheduled into systems tests this fall.

3. Drilling and testing a shallow injection well (90 psi) in early FY-81.

EXPERIMENTAL SHALLOW INJECTION WELL

Within the last two months, both the State of Idaho and EPA have adopted regulations which govern the construction and use of geothermal injection wells. Both regulations prohibit the disposal of geothermal fluids where there is the potential for migration between the injection zone and aquifers protected as drinking water sources (see Appendix A). The hydraulic connection between RRGI-6 and MW-4 indicates that there is a potential for fluid migration in Raft River. At a meeting on July 30, 1980, the Idaho Department of Water Resources, which administers Idaho's injection regulations and which will implement EPA's regulations, stated that injection into RRGI-6 at wellhead pressures of 250 to 500 psi could not be permitted under either the State or Federal regulations. High pressure injection in Well-6 creates a pressure response at Monitoring Well-4 located ~8000 ft. from Well-6, but observation wells nearer Well-6 do not show the same pressure response (Well-6 is open 300' in the "thief zone"). This evidence of a rapid pressure response indicates a fracture exists in the "thief zone." The thief zone was identified on lost circulation zones described from drilling logs. In Well-6 the Zone contained some fractures identified from USGS Logs, while in Well-3, it was described as a semi-consolidated gravel horizon. No Thief Zone was identified in Well-7. Testing indicates the zone will readily take water, but at a high pressure point source discharge it forces water through fractures extending through an upper boundary, thereby affecting the upper aqüifers. Calculations indicate that through a low pressure multiple-well system, this communication would not exist, although this has not been confirmed through actual tests.

Three options for bringing RRGI-6 into compliance are:

1. <u>The upper 300 feet of open hole in RRGI-6 can be cased off and cemented.</u> This upper zone may include soft seidment fractures (Scott Keys, personal communication), which communicate with the aquifer tapped by MW-4. It has been estimated by both the USGS (Schimschal and Keys, personal communication) and Terra Tek (in press, 1980) that 50% of the water injected into RRGI-6 enters the formation which has been described as the thief zone in the first 300 feet below the casing. Casing off

this zone would reduce the capacity of RRGI-6 by approximately 50%. Such action would not guarantee that fluid would not reach the upper aquifers since there is no well-defined confining layer which would prevent upward movement from the lower open hole portion of RRGI-6 through the theif zone to the upper aquifers.

2. Injection can continue into RRGI-6, but at lower pressures (150-200 psi). This would reduce the injection capacity by an estimated 40%. Some communication with upper aquifers would still exist.

3. Use of RRGI-6 as an injection well can be discontinued. This is the option recommended by the State as the only sure way of preventing communication between RRGI-6 and upper aquifers.

If the injection capacity of RRGI-6 is reduced in order to comply with regulations, it will be necessary to provide additional fluid disposal capability to operate the 5MW(e) plant. The avaiable options to accomplish this are:

1. Deep (~5000 ft.) wells injecting into metamorphic rocks,
2. Additional intermediate-depth (2000-3000 ft.) wells injecting into partly lithified sediments, and
3. Low pressure wells injecting into the high permeability sediments of the thief zone which occur between 1500 and 2800 ft.

Deep injection wells would require higher injection pressures to accept the same amount of fluid as intermediate wells due to the higher pressure in the deeper zones. The increased cost of drilling such wells and the increased pumping costs would make this the most expensive option. Deep wells would need to be located in an area of fractured rocks to have sufficient injection capacity. It is possible that movement of the injected fluids into the irrigation aquifers or into the production zone would occur along these fractures. This is evidenced by the existence of hot, shallow artesian wells (BLM & Crook's) which have water chemistry similar to that of the deep system. Injection at high pressures could accelerate this upward migration.

High pressure injection into other intermediate-depth wells, including RRGI-7, may also result in communication with upper aquifers. Long-term (>10 days) testing of RRGI-7 at high flow rates is necessary to determine if this will be a problem. Injection at RRGI-7 is presently into an upper zone of high matrix permeability and into deeper zones of low-to-moderate permeability. No fractures have been identified in this well.

Initial evaluation indicates that "thief zone" injection is the most promising solution considering environmental, technical, and economic factors. If a thief zone well could be located in an area where fractures are unlikely and where a less permeable layer overlies the thief zone, upward movement of the injected fluid would be inhibited. If low injection pressures are used, no new fractures would be formed and lateral movement in the highly permeable thief zone would predominate over upward movement toward the irrigation aquifers.

There are three possible methods to test the technical feasibility and environmental acceptability of thier zone injection:

1. Shot perforate and test an existing well such as RRGP-4.

2. Test RRGI-6 which presently injects into the thief zone and deeper moderate permeability zones at low pressures (90 psi). This would test the communication of the fractured zone with the upper aquifers, but would not test the flow rate or communication of a thief zone well in an unfractured area.

3. Drill a new shallow well to a depth of about 2250 ft. with open hole completion or screens in the thief zone.

Perforating

Perforating RRGI-6 or RRGI-7 would not be beneficial because RRGI-6 is already open in the thief zone and no thief zone has been identified in RRGI-7. If an existing well, RRGP-4, RRGI-6 or RRGI-7 were perforated as a test to evaluate injection to the thif zone, its cost and effectiveness are questionable. The estimated cost of bringing in a rig, renting a packer with tubing, perforating the casing, acidizing the perfs and testing the zone is $160K (Table I). If the test failed, returning the hole to its original condition is estimated to cost an additional $100-$200K, based on industry experience with "squeeze" treatments.

TABLE I

Cost of Perforating

Perforating (500 shots - 0-2000 ft)	$15,000*
Acidize perfs	25,000*
Rig with tubing, packer and rentals (minimum 12 days of testing)	38,000*
Test support (Reservoir Engineer & RRFO)	80,000
	$158,000

*Experience gained from PON project at St. Mary's Hospital, Pierre, South Dakota, on comparable depth (2100 ft.) and job design, escalated 25%.

Both the Idaho Department of Water Resources & EG&G reservoir engineers have verbally expressed uncertainties about the validity of testing true thief zone injection in a perforated hole. The open area of perforated casing is approximately 2%, while the porosity of the formation is approximately 25%. The jagged shape of the perforations allows sand bridges to form easily, further decreasing the open area.

Tests on perforated casing would show some difference between poor production due to perforations or low permeability of the aquifer; however, it would be very difficult to quantify this difference. For the specific reasons given in Table II, none of the existing wells are located or constructed to adequately test a thief zone well. Based on the costs and potential effectiveness, testing perforated sections of the wells is not considered feasible.

An analysis of the wells that are candidates for perforation is summarized in Table II.

Porous, permeable zones and fractures that readily accept fluid (lost circulation while drilling) also accept cement. Cement penetration in these zones would be much greater than the zone penetrated by perforation. Penetration of cement in a fracture at RRGP-5 was shown to be 10 feet as evidenced from cores taken in the offset hole. Therefore, perforation

TABLE II - PERFORATION CANDIDATES

RRGP-4	Prior to the fall of 1978, this well was an experimental injection well, RRGI-4, open-hole from 1900-2840 ft. in the thief zone. During the injection testing of RRGI-4, pressure responses were seen in the shallow BLM, Crook, and USGS well indicating a direct communication through a fractured system with upper aquifers. It is likely that even low injection pressures would result in communication with upper aquifers.
RRGP-5	The well is presently included in the 5MW(e) system as a backup production well. This well shows definite connection, at depth, with RRGE-1. The upper part of the well has never been tested. Communication with the geothermal resource (and thus interference with RRGE-1) or through fractures to the shallow aquifer is possible. Perforating and testing this well would destroy its usefulness as a geothermal well.
RRGI-6	High pressure injection tests into this well show pressure response in MW-4 in about 5-6 days. It is probable that this is a unique situation since it is suspected that fracture connection to the near-surface (1000 ft.) exists only in MW-4. This well is presently open to the thief zone and layers above the thief zone have low-to-moderate permeability. Therefore, perforating would not be required. Testing just the thief zone in this well would require setting an open-hole packer, which is ineffective in poorly lithified sediments.
RRGI-7	This well has been interpreted to have a high matrix permeability and can be used as a high-pressure injection well. Long-term testing will be conducted to determine if hydraulic connection with the upper aquifers exists. No actual thief zone or lost circulation zone was identified during drilling of this well.

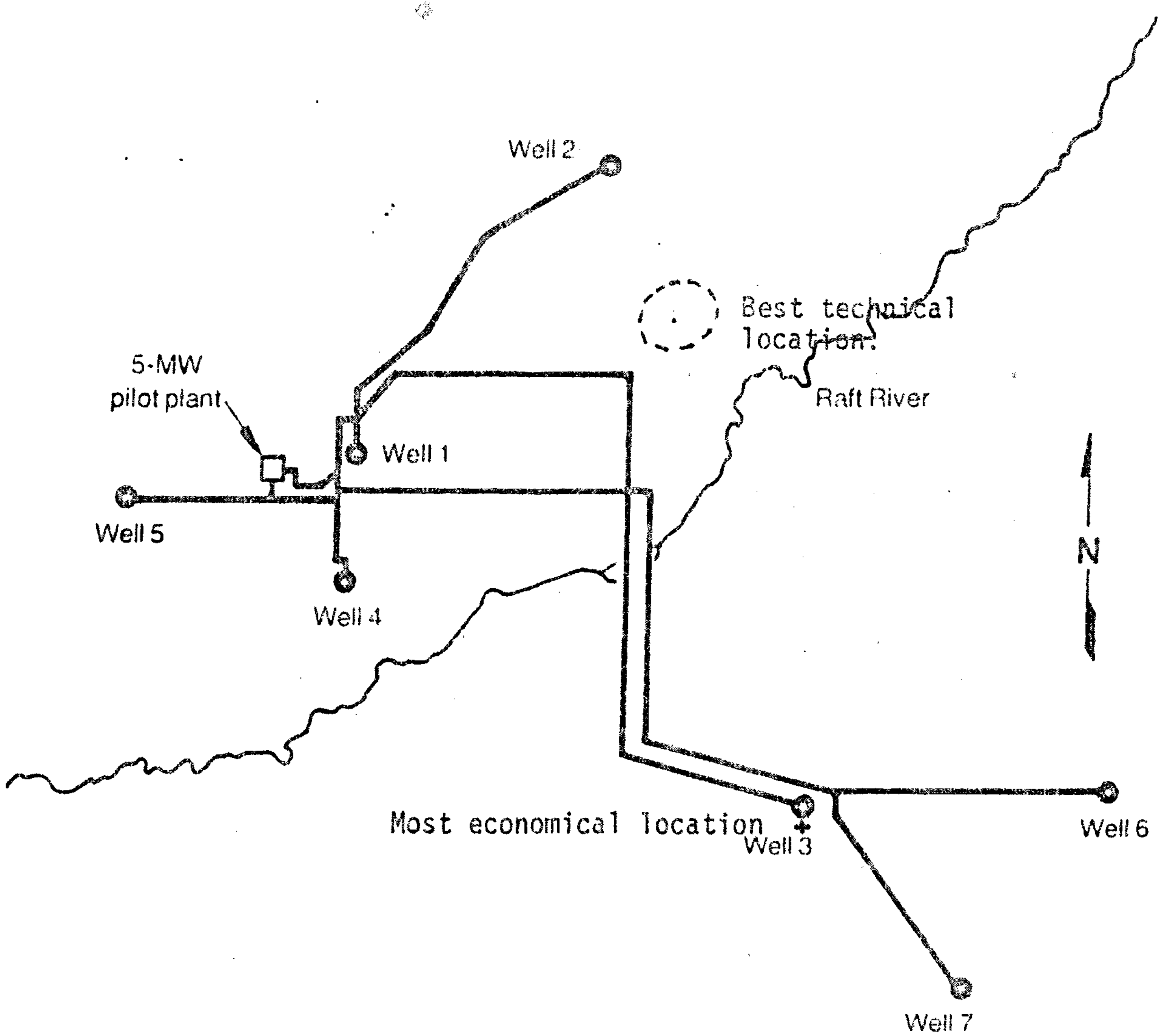
would not be effective in "opening" the hole. The effectiveness of perforating vs openhole completion was evaluated during tests at INEL-1, Ore-Ida, St. Mary's and Utah Roses. During INEL-1 tests, we observed a five-fold reduction in flow on tests "behind perforations" as compared to open-hole. Other testing indicated no appreciable production increase with the perforations. This could be attributed to either lack of permeability or cement invasion of potential production zones. Because lost circulation zones or zones of high permeability were evidenced during drilling and logging, it is felt that non-production can be attributed to cement invasion.

Shallow Thief Zone Test Well

Drilling a test well into the thief zone appears to be the most feasible option. Drilling a thief zone injection well in an unfractured area with a confining layer would test the theory that communication with upper aquifers is along soft sediment fractures and can be avoided by proper well location. Testing the well would also provide data on the injection capacity of the well. This information cannot be obtained by testing any of the existing wells. In determining the location of such a test well, cost, schedule, and technical considerations must be taken into account. The most technically viable location in the withdrawal area is to the northeast of MW-2 where the injection pipeline running east from the power plant turns south along the section line between sections 23 and 24, T15S, R26E (see map). The hydrogeologic advantages of this site include:

1. The injection water will enter a groundwater system which flows down the Raft River valley, away from the primary production area. This will reduce the possibility of cold injection water entering the power plant production zone.

2. This site is estimated to be of sufficient distance from RRGE-1 that the cone of influence will not induce the flow of cold injection water toward RRGE-1.



Recommended thief zone well locations

3. This site is sufficiently removed from the suggested BLM fault so that injection water should not enter the fault and rapidly appear in the near-surface aquifers or in the primary production wells.

4. This site does not appear to be as susceptible to possible flooding as sites along the injection pipeline farther to the south and closer to the Raft River.

Disadvantages of this site as a test well location are 1) the land is privately-owned, 2) not enough monitor wells exist nearby, and 3) production from shallow warm wells (e.g., Crook's well) would seriously affect the data from the existing monitor wells.

The location which is the most timely and economically feasible is along the injection pipeline near RRGE-3. The advantages of this site are: 1) it is the most economical (relative to pipeline and monitoring costs), 2) it is on public land within the withdrawal area, and 3) it is the location with the best subsurface data. Data from RRGE-3 suggest the thief zone will be intercepted from about 1600 to 2250 ft. The location is surrounded by monitor wells (MW-3, MW-4, USGS-2, the 100-ft. pit monitor well, and a 200-ft. domestic well). These monitor wells have nearly two years of historical records. Since RRGE-3 intersects a major fracture, the well will be located to avoid this fracture system.

During drilling the well, the presence or absence of a confining layer should be determined. If this feature is found, the casing can be set to the depth of this layer and the top of the open-hole injection zone begun.

The well should be drilled and tested during a period when no activity is taking place in other wells, particularly the injection wells. All monitor wells will be instrumented to observe any pressure response that might occur as a result of injection. Chemical logging of circulating fluids in the shallow injection well will be performed to determine near-surface water chemistry. Based on logs from RRGE-3, it is anticipated that a porous conglomerate and sandstone will be encountered at about 1600 ft., and circulation may be lost at about 1900 ft. RRGE-3 logs indicate very porous rock conditions are nearly continuous from 1600 to 2250 ft. An excellent receiving zone is noted on the logs from 1900 to 1950 ft. Low permeability zones exist above this zone.

APPENDIX A

INJECTION REGULATIONS

1. EPA Underground Injection Control Program: Criteria and Standards Federal Register, June 24, 1980.

Under these regulations, injection wells which are associated with "the recovery of geothermal energy to produce electric power" fall under Class III provisions. Subpart D of the regulation, Criteria & Standards applicable to Class III wells, states that "Class III" wells shall be cased and cemented to prevent the migration of fluids into or between underground sources of drinking water." Under these regulations, the shallow aquifers are classed as underground drinking water sources (TDS < 10,000 mg/L).

2. State of Idaho Regulations and Standards for the Construction and Use of Waste Disposal and Injection Wells, adopted June 2, 1980.

Under these regulations, wells which "will discharge wastes which are likely to migrate to a drinking water source" are Class I wells. For Class I wells, "the concentration of each chemical constituent in the discharge shall not exceed Drinking Water Standards for that chemical constituent, in the receiving water, whichever is less stringent. Waste disposal or injection wells that discharge directly into voids that may conduct waste water directly to the (drinking water) aquifer, must comply with the water quality standards of wells discharging effluents directly into ground-water." The water quality of the injected fluids at Raft River does not meet these requirements.

INJECTION OPTIONS SUMMARY TABLE

	Shallow	Intermediate	Deep
Depth (feet)	∿ 2000	∿ 3500	∿ 5000
Pressure (psi)	100	400	400
Flow/Well (gpm)	400	800	800
Well (flow @ Press)			
#6	400 @ 100	800 @ 400	800 @ 400
#7	800 @ 400	800 @ 400	800 @ 400
#8 (experimental)	400 @ 100	- -	- -
#9 new	400 @ 100	800 @ 400	800 @ 400
#10 new	400 @ 100	- -	- -
Cost			
#6	$ 50K	$ 400K	$ 500K
#7	- -	- -	500K
#8 (experimental)	250K	- -	- -
#9	200K	600K	- -
#10	200K	- -	1,000K
Pumps	0	150K	200K
Pipelines	250K	250K	250K
Monitor Wells	150K	150K	150K
Installation Cost	$1,100K	$1,550K	$2,600K
Operating Cost	min.	high	higher