The objective of this report is to analyze and summarize all data acquired to date. The specific objectives of Table 1 are to define the hydrologic production and injection characteristics of the wells, the thermal characteristics of the production wells, and the impact of production, and injection on the overlying ground waters. Table 2 summarizes the data analysis technique used. Constant discharge variable drawdown tests were used to facilitate boundary analysis techniques. The only exception to this are the data for the well No. 1. Semi-logrithmic plots of wellhead pressure, bubbler pressure and Hewlett-Packard downhole pressure vs time are used. The advantage of this technique is that T, which is transmissivity and kH, the intrinsic transmissivity, can be calculated even with significant well losses. The equation, $T=110\ (Q/s_{10})$ is used to calculate transmissivity for 280^{o}F water with T in gallons/min and s_{10} the drawdown or pressure buildup per log cycle in. psi. The value for kH in millidarcy-ft is approximately 1150 times the ratio of Q/s10 for 280^{o}F water. The kH is about 10 times the value for T. For the data, presented values for Q/s_{10} and Q/ will be used because of the the six complicating factors listed under Item 4 in Table 3. The first complicating factor[a] concerns the number of producing and receiving zones in the 1366 ft sections of uncased bore hole. The number of producing and receiving zones is generally unknown. There are several producing zones, in some of these wells. Theoretically, the calculations are based on a single homogeneous, (isotropic) aquifer of infinite areal extent. With more than one producing and receiving zone, the conditions actually existing in the well bore do not satisfy theoretical conditions necessary for specifying T and kH. (b) The second complicating factor (b) results since the producing/receiving zones in a wellbore can be presumed to have different T values, different storage coefficients, different boundary conditions and often different fluid temperatures. The theory used is for a single ideal aquifer having a fixed T and a fixed S. The items listed in (b) well can be expected to lead to commingling effects between the different producing/receiving zones. (c) The third complicating factor results since the injected fluids often have a different temperature than that of the native fluids in the receiving zones. This leads to complications because zones temporally develop up around the well bore which have different temperatures and viscosities and therefore, different friction losses than the displaced native fluids. This can result in nonideal pressure buildups and possibly temporally dependent well losses depending on wellbore preheating prior to injection. (d) Fracture flow occurs in the wells intercepting fault systems. Fracture flow appears to be less significant in the injection wells than in the production wells. Another problem (e) results when interpreting early time data. Generally it requires up to 600 minutes of testing injection or pumping before stabilising the bore hole fluid temperatures and density profiles if the well has not been preheated prior to testing. Therefore, it not always possible to quantatively define boundaries occurring during the first 600 minutes of a test. Another complicating factor (f) results since the ratios of Q/s10 are sometimes dependent of Q as will be seen in the data for RRGE 2. Therefore, there is no unique T or kH value for the aquifers penetrated by the wellbore. The complicating factors listed above precludes the use of a theoretical model based on a homogeneous isotropic aquifer of infinite areal extent. The drawdown and buildup data plot as linear trends on semilogarithmic graphs after a suitable lapse of time following the beginning of the test. The extrapolation of the observed linear trends to the desired time permits the determination of drawdowns and buildups without recourse to a theoretical mathematical model.

The estimated storage coefficients are 5×10^{-4} for production wells and about 5×10^{-3} for injection well RRGI-6. A summary of drawdown and buildup after 5 years of continuous operation is contained in Table 3. The summary table of this data considers two schemes for pumping RRGI-1; (1) pumping of 1230 gpm, and (2) the pumping at 660 gpm. The remaining production wells are currently planned to be pumped in the vicinity of 625 to 645 gpm. Injection well 6 might receive as much as 1463 gpm and injection well 7 might receive as much as 410 gpm with the limitation of 600 psi buildup after 5 years of continuous pumping. A previously reported limit of 700 psi at the wellhead has been reduced due to hardware limitations. These are the drawdowns expected after 5 years of continuous pumping assuming no additional equivalent boundary effects and no additional well interferences.

Data highlights for well RRGE-1 are indicated in Table 4.

One pumping test is addressed. This test was a variable Q - variable drawdown test and is not very amenable to analysis. The wellhead shutin pressure on this test was 174 psig. The bubbler shutin pressure was 422 psig. Maximum wellhead temperature which was observed 11-15-78 was 280^{o}F. Higher temperature may result at hgiher well discharge rates. The borehole is uncased from 3622 to 4989 ft. All the plots are bubbler pressures. These are more accurate than wellhead pressure data.

The best data available to date are plotted in Figure 1. This is a semilogarithmic plot of bubbler pressure versus time. The discharge rate, Q, for this test ranged from 1100 to 880 gapm. The stabilized at about 880 gal/min after approximately 100 minutes of pumping. The slope of the data is about 10 psi/log cycle. Estimates for the drawdown that would occur after 5 years of constant discharge assuming no interference and no other boudnary effects were calculated using these data (Table 4). For discharge rates of 1230 gpm and 660 gpm, the drawdowns after 5 years of constant discharge assuming no interference and no additional boundary effects would be 461 psi and 248 psi respectively. It appears that RRGE-1 is the best production well.

The data highlights for RRGE-2 are listed in Table 6. The shutin wellhead pressure for RRGE-2 ranges from approximately 122 to 142 psig while the shutin bubbler pressure is 440 to 460 psig depending on whether the wellbore fluid is "cold" or heated by flowing to its maximum wellhead temperature of 283^{o}F. The well has uncased borehole over a depth interval from 4227 to 6543 ft. and is the deepest well in the Raft River Project. Test data from ten tests are available. Pumping rates ranging from 200 gpm up to 800 gpm. The 210 gpm test used artesian flow while the remainder used a pump. The hydrologic features are listed in Table 7. This well is known to have three major production zones. An equivalent barrier boundary affects the drawdown data after about 15 minutes of pumping. This would be equivalent to a linear impermeable infinite boundary at a distance of 50 ft from RRGE-2 another equivalent barrier boundary affects the drawdown data after about 333 min. of pumping. This would be equivalent to an infinite linear impermeable barrier boundary perpendicular to the boundary which occurred after about 15 minutes and at a distance of 100 ft from RRGE-2. The well exhibits nonideal drawdown characteristics.

Temperature profiles in the borehole following the injection of cold water indicate three major production zones (Figure 2). The production zones which accepted cold water during injection exhibit depressed temperatures in comparison to the relatively impermeable sections of the borehole.

The three major receiving zones preclude the use of an idealized mathematical model based on a single aquifer. Commingling effects between these aquifers becomes a main problem. Figure 3 depicts data collected by Witherspoon and Associates using the downhole Hewlett-Packard (HP) downhole pressure-temperature probe. The well was allowed to free flow at a constant rate of 210 gpm. The slope for the first 15 minute segment of 4.75 psi per log cycle results in a Q/s10 ratio of 44.2/gpm/psi/log cycle. The slope approximately doubles to 11.3 psi/log cycle for the 15 to 333 min. segment and then doubles again to 20 psi/log cycle for the data beyond 333 min. The Q/s10 values for these data segments are 18.6 and 10.5 gpm/psi/log cycle respectively. The data for this test are the only data available which exhibit equivalent boundary during the initial 333 min. of pumping. It is assumed that these equivalent boundary effects occur during all subsequent pumping tests.

Additional pump test versus time flow data are plotted in Figure 4. These are semilogapithmic plots of pressure decline since flow began for five tests at flow rates of 200, 250, 300, 350, and 400 gpm. The Q/s10 ratios vary from 16.0 gpm/psi log cycle at 200 gpm to 11.76 gpm/psi/log cycle at 400 gpm. These data indicate that the ratio Q/s10 is dependent on Q. Presumably T and kH are also dependent on the pumping rate. Thus, a single value for T or kH is inadequate to define this hydrologic parameters.

An unconventional technique was used to develop drawdown equations. Based on the data available to date, it is assumed that no additional equivalent boundary effects occur beyond 333 min. after beginning pumping. It was further assumed that the drawdown data plotted as linear trends on semilogarithmic plots. Thus, knowing the drawdown at 333 min. as a function of Q (intercept for a linear regression equation) as well as the Q/s10 ratio as a function of Q (slope for a linear regression equation) an equation may be a developed predicting drawdowns for pumping durations greater than 333 min.

*Another pump test at 800 gal/min, began May 10, 1978. Figure 5 is a semilogacithmic graph of bubbler pressure vs time in minutes. The slope of the linear data trend from 333 min. to (700) min. had a Q/s10 ratio of only 10.0 gal/min/psi/log cycle with a drawdown of 344 psi after 333 min of pumping.

Another test at a pumping rate of 740 gal/min began May 30, 1978 (Figure 6) The Q/s10 ratio for the data segment beyond 333 min is again 10.0 gpm/psi/log cycle. The drawdown at 333 min., 275 psi, was calculated by extrapolating the linear trend for data where t 500 min. back to 333 min. The well was shut in for a short period after pumping approximately (300) min. An error on the order of 9 psi may have resulted in estimating drawdown at 333 min. using this procedure.

Another pump test began on January 10, 1979 at a rate of 700 gpm (Figure 7) The linear data trend beyond 333 min. has a Q/s_{10} of only 8.41 gpm/psi/log cycle The drawdown was 201.7 psi after 333 min. of pumping.

The latest data are for the test beginning March 20, 1979 (Figure 8). Bubbler pressure data were obtained using both a Paroscientific digiquartz recorder and Heise pressure gauge. Excellent quality data were collected until 1800 min. Somewhat erratic data result after approximately 3000 min of pumping probably because of a 10 gal/min change in the flow rate due to leakage across one or more of the valves in the pipeline conveying water from RRGE-2 to RRGI-6. Pressure testing of a pipe line at RRGE-3 resulted in a pressure increase presumably because of leakage into the pipeline conveying water from RRGE-2 to RRGI-6 which resulted in a lower pumping rate at RRGE-2 since the flow rate was controlled at RRGI-6. The Heise gauge was rezeroed which appears to have affected the data by increasing the pressure by about 10 psi. The digiquartz data were erratic from approximately 1800 min to 10,000 min because of an apparent pressure stabilization problem with the quartz crystal pressure transducer following purging of the bubbler. The deviation of the pressure data after 12,000 min from the pressure trend that developed at approximately 400 min. is probably related to pipeline net leakage rate decrease as a result of pipeline pressure testing at RRGE-3. The change in slope at approximately 12,000 min may also have resulted from a recharge boundary effect or equivalent. A preliminary assessment of these data suggests that a changing flow rate rather than a hydrologic boundary affected the data after approximately 12,000 min.

Projected drawdons at RRGE-2 were calculated by assuming the drawdown data plots as a linear regression after 333 min. of pumping. Thus, the drawdown after 333 min of pumping and the slope of the regression need to be defined. Figure 9 is a graph of the drawdown after 333 min. as a function of pumping rate. The drawdowns after 333 min of pumping followed a power curve. The regression slopes after 333 min of pumping are plotted in Figure 10 as a function of pumping rate. Interference effects between wells may have affected the data collected at discharge rates of 740 and 800 gpm. During these tests, water was pumped from RRGE-2 and injected into RRGI-4. Interference effects were definitely observed in MW-1, MW-2, USGS-3 and in the BLM offset well while conducting these tests. The injection of the water into RRGI-4 may have interfaced with the pressure drawdown at RRGE-2 thereby resulting in an underestimated value for s_{10}. The equations for drawdown after 333 min and the slope s_{10} after 333 min were combined into an equation predicting the drawdown after five years of continuous pumping with no interference effects from other wells and no change in the boundary conditions. Figure 11 contains a plot of this equation. The drawdown is not directly proportional to the pumping rate. Well RRGE-2 is one of the more interesting wells because it doesn't behave as predicted by most theoretical equations.

The data highlights for RRGE-3 are listed in Table 8. Well RRGE-3 has a shutin in wellhead pressure of 126 psig, a bubbler pressure of 420 psig and a maximum wellhead temperature in the vicinity of 296^{o}F. The borehole is uncased from 4255 to 5929 ft. and is triple legged. The pump test data discharges ranged from 592 to 788 gal/min. Hydrologic features are listed in Table 9.

A recharge boundary or equivalent hydrologic condition affects the drawdown data after approximately 3533 min. of pumping. Discharge tests completed while drilling the well indicate that the majority of the production originates from Leg C. Legs A and B may be partially filled with drill cuttings. RRGE-3 has the highest wellhead temperatures of all the Raft River wells.

The first pump test of significance on the completed well began June 29, 1977, at a discharge rate of 788 gpm. Figure 12 is a graph of bubbler pressure versus time. The Q/s_{10} ratio had a value of 4.237 gpm/psi/log cycle after approximately 400 min of pumping. Approximately 400 min of pumping were required for thermal and hydrologic conditions to stabilize such that the data plotted as a straight line.

The next pump test at a rate of 592 gpm began July 6, 1977, (Figure 13). The data plotted as a linear trend having a Q/s10 ratio of 3.677 gpm/psi/log cycle from 600 min until 3325 min. From 3325 min until approximately 13,000 min the data plotted as a straight line having a Q/s10 ratio of 5.148 gpm/psi/log cycle. The recovery data for this test are plotted in Figure 14 which is a graph of calculated recovery s' versus the time since shut in. The calculated recovery is the difference between the extrapolated pressure that would have resulted had the pressure continued to decline at 115 psi/log cycle (Figure 13) less the observed pressure during recovery. The Q/s10 ratio during recovery was 5.365 gpm/psi/log cycle which compares favorably with the 5.148 gpm/psi/log cycle for the drawdown data.

The next pump test conducted at a discharge rate of 603 gpm began November 17, 1977, (Figure 15). The data followed a straight line plot having a Q/s10 ratio of 4.824 gpm/psi/log cycle from approximately 400 min. until the end of the test at (1400) min.

The next pump test began November 28, 1977, and had a well discharge rate of 603 gpm. The Q/s10 ratio from approximately 500 min until 3899 min was

4.246 gpm/psi/log cycle. The Q/s10 ratio was 6.153 gpm/psi/log cycle for the data segment from 3899 min to (32,000) min. The recovery data plotted in Figure 17 resulted in a Q/s10 of 4.711 gpm/psi/log cycle for the data prior to 1369 min. Beyond 1369 min the data followed a trend having a Q/s10 of 7.179 gpm/psi/log cycle. The data prior to 1369 min result in a Q/s10 value comparable to other test values. The data beyond 1369 min are believed to have been affected by extraneous conditions which resulted in an invalid Q/s10 value and an intersection time for the two linear data segments which is too low.

Another pump test on RRGE-3 began on January 31, 1978. The pumping rate of 650 gpm resulted in a linear data segment from 1000 to 3375 min that had a Q/s10 value of 3.714 gpm/psi/log cycle. The data segment from 3375 to 13,085 min had a Q/s10 ratio of 5.328 gpm/psi/log cycle. The time of intersection of the two linear data segments of 3375 min appears to be valid as do the Q/s10 ratios for the linear data segments.

The linear data segments for all the drawdown and recovery data are plotted in Figure 19. Projections of the linear data segments for the period beyond 3899 min are also indicated. The recovery data for the November 28, 1977, test are somewhat suspect and have been eliminated from calculations for the predicted drawdown curves. Table ~~9~~ 10 is a summary of the pump test data on RRGE-3. Table 11 lists the data used to generate the drawdown estimates after five years of continuous pumping with no well interference. The logarithmic mean of 2.42 gpm/psi for the ratio of Q/drawdown at 3533 min was used to calculate the drawdown at 3533 min. The logarithmic mean of 1.935 gpm/psi for the ratio Q/increase in drawdown from 3533 min to five years was used to calculate the increase in drawdown from 3533 min to five years. These drawdown segments are plotted in Figure 19. Figure 20 contains graphs of the predicted drawdown after five years of continuous pumping with no interference and with an estimated 100 psi of net interference. With a 625 gpm pumping rate, a drawdown between 479 and 579 psi can be expected after 5 years.

RRGP-4AB

The data highlights for RRGP-4AB are listed in Table 12. The shut-in wellhead pressure is approximately 130 psia with a maximum downhole temperature of 289°F. Uncased borehole extends from 3470 ft to 5224 ft and 5128 ft in the two legs. Table 12 lists the hydrologic features.

A flow test at 15 gpm was used to evaluate the production characteristics of the well. A warm-up flow of 10 gpm preceeded the 15 gpm increase in flow which served as the flow test (Figure 21). Wellbore temperature induced density changes appear to have significantly affected the data for approximately 100 min. Figure 22 is a graph of the recovery data. Figure 23 is a graph of the predicted drawdown versus time for flow rates of 50 and 100 gpm. A drawdown in excess of 500 psi after 36 hr of pumping at 100 gpm indicates the well is a very poor producer.

RRGP-5B

Data highlights for RRGP-5B are listed in Table 13. The shut-in wellhead pressure is approximately 144 psia. The maximum downhole temperature is 272°F which is the lowest temperature of the Raft River production wells. The principle hydrologic feature (Table 15) is a possible equivalent recharge boundary occurring approximately 100 min after initiating flow. Figure 24 contains semilogarithmic graphs of wellhead pressure versus time since production began and time since wellhead shut in for flow tests at 40,190 and 280 gpm. The drawdown and recovery data exhibit strong similarities. Figure 25 contains the drawdown data plotted in Figure 24. Specific capacities at 10 min range from 3.12 to 4.17 gpm/psi.

Wellhead pressure data for a 72 hr prodution test where the flow rate was 140 gpm are plotted in Figure 26. An instrument malfunction resulted in questionable data after 42 min of flowing. The subsequent data suggest a decrease in the slope which could have resulted from an equivalent recharge boundary condition affecting the data.

The specific capacities after 10 min of withdrawal areplotted in Figure 27 as a function of the discharge rate Q. It appears that the specific capacity is dependent on the discharge rate.

Table 16 contains a summary of the test results. Table 17 lists the expected drawdowns after five years of pumping at various rates assuming no interference and no boundary effects. At a projected pumping rate of 645 gpm approximately 300 psi of drawdown can be expected.

RRGI-6

The data highlights for RRGI-6 are listed in Table 18. Shut-in wellhead pressure varies from 0 to 60 psig depending on whether or not the fluid in the wellbore is relatively cold or hot. The maximum downhole temperature observed prior to extensive injection testing was 252°F. This well has uncased borehole from 1698 to 3888 ft.

The hydrologic features for RRGI-6 are listed in Table 18. This well has a ~~casing~~ borehole immediately below the casing. Well losses can be expected to

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betemporally dependent. An equivalent recharge boundary affects the data between 500 and 1700 min after beginning injection. Injection into RRGI-6 may result in 33 ft of interference at RRGI-7. RRGI-6 is a high capacity injection well.

The initial injection at a rate of 800 gpm using 110^{o}F water began on May 1, 1978, (Figure 28). The step in the data at approximately 1 min resulted from the second drill rig pump coming on line. A 6 min pump failure occurred at approximately 40 min. The ratio of Q/s10 is approximately 29.63 gpm/psi/log cycle. Recovery data plotted in Figure 29 resulted in a Q/s10 ratio of 23.52 gpm/psi/log cycle.

A flow test at a rate of 207 gpm began November 9, 1978. Wellbore fluid heat up resulted in an increasing wellhead pressure after 4 min. Density corrected drawdown data resulted in a Q/s10 of 79.0 gpm/psi/log cycle. The recovery data plotted on Figure 31 had a Q/s10 of 82.8 gpm/psi/log cycle. The Q/s10 values for the 207 gpm test are considerably higher than those for the 800 gpm injection test.

A 700 gpm injection test began on January 9, 1979 (Figure 32). A Q/s10 of 25.24 gpm/psi log cycle resulted between 4 min and 38 min. The Q/s10 was 23.17 gpm/psi/log cycle for the data following resumption of injection after a brief pump shut down. A Q/s10 value of 21.54 gpm/psi/log cycle resulted during recovery (Figure 33).

A second 700 gpm injection test began January 10, 1979, (Figure 34). A Q/s10 of 17.75 gpm/psi/log cycle resulted for the data prior to 300 min. A Q/s10 of 42.87 gpm/psi/log cycle resulted for the data collected after 300 min. Figure 35 contains pressure data for the Hewlett-Packard downhole pressure-temperature probe. A Q/s10 of 42.27 gpm/psi/log cycle resulted for the data collected after 300 min. Temperature induced errors affected the data prior to 300 min. The data for the 700 gpm test beginning January 10, 1979, indicates phenomenon equivalent to a recharge boundary affected the data after approximately 300 min of injection.

Interference effects may have occurred at RRGI-7. Figures 36 and 37 are hydrographs for RRGI-7. The increase in head, s", beginning on January 9, above the trend that developed prior to injection is plotted in Figure 38. The pressure trend would result in a 33 ft increase in head at RRGI-7 after 5 years of continuous injection at 700 gpm into RRGI-6.

Another injection test at a rate of 600 gpm began March 20, 1979 (Figure 39). The Q/s10 for the initial data plotted is 27.1 gpm/psi/log cycle. Increased temperature of the water resulted in an upward displacement of the initial data segment. A change in Q/s10 ratio to 47.62 gpm/psi/log cycle occurred at approximately 1700 min. A 10 min pump outage resulted in a small displacment in the data beyond 10,360 min. The linear data segments suggest excellent control in maintaining a constant flow rate.

The expected buildups in wellhead pressure after 5 years of injection at a constant rate assuming no interference, 258^{0}F injection water and no additional boundary effects are listed in Table 21. The close agreement between the 600 gpm predictions based on the January 10, 1979, data and the March 20, 1979, data indicate test results are reproducable. With a wellhead pressure limit of 600 psi, an injection rate of 1463 gpm is possible.

<u>RRGI-7</u>

The data highlights for RRGI-7 are listed in Table 22. The shut-in wellhead pressure varies from -9 to 2 psig. Maximum downhole temperature is in excess of 200°F. An 1814 ft section of uncased borehole exists between depths of 2044 to 3858 ft. Injection test data will be presented for five tests. This is a relatively low capacity injection well.

The first injection test Figure 40 was performed with the drill rig on site. The Q/s10 for the first data segment is 3.75 gpm/psi/log cycle while injecting at 840 gpm. Table 22 is a summary of the test data collected while the drilling rig was on site. The most reliable data are believed to result from the first step injection test. The data for the predicted wellhead pressure after five years of injection at a constant rate assuming no interference or boundary effects. Based on the linear data segment for the 840 gpm test and a 600 psi limit on wellhead pressure, an injection rate of 405 gpm could be sustained for five years assuming no interference or boundary effects.

Additional tests have been attempted on RRGI-7. A Halliburton pump truck was used to inject water at an indicated 400 gpm (Figure 42). The data for the test beginning November 16, 1978 resulted in a Q/s10 of 3.336 gpm/psi/log cycle while injected 58°F water. Pump failure terminated the test. The data for the test beginning November 17, 1978, are believed to be invalid due to air entrainment in the injected fluied. Possible interference effects of 0.09 psi may have resulted at RRGI-6.

Conclusions

The conclusions based on testing to date are summarized in Table 23. Adequate injection capacity is available from wells RRGE-1, RRGE-2, RRGE-3 and RRGP-5 to provide 25601 gpm. The injection capacity is insufficient to dispose of the spent geothermal fluids. Wellhead temperatures for wells in the Bridge Fault system can be expected to range from 270 to 283^{o}F whereas the wellhead temperature for the RRGE-3 well in the Narrows Structure is expected to be 296^{o}F. Numerous discontinuities as listed in Table 24 have affected the pressure trend observed to date. Clearly discernable interference effects have not be observed between either production wells or injection wells. Interference effects between production and injection wells have not been determined to date. Hydrogeologic data indicate a heterogeneous geothermal aquifer system. Additional scheduled testing can be expected to provide additional information on the thermal and hydrologic characteristics of the wells at the Raft River KGRA.