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1. OBJECTIVES

The objectives in testing included:

1. Assessment of Well RRGI-6 and receiving zone responses to injection of 95 – 140°C fluid.

2. Investigation of aquifer inhomogenities in the regions of wells RRGE-2 and RRGI-6.

3. Investigation of potential mutual interferences within the Raft River KGRA aquifer system.

4. Prediction of behaviour of Well RRGI-6 to extended periods of injection and to other temperature fluids.

5.

2. SUMMARY OF RESULTS

The March-April 21 day injection test in Well RRGI-6 has shown the likelihood of direct communication between the injection zone and shallow groundwater aquifers penetrated by Monitor Well 4. Other Monitor wells in the region of the injection field indicate probable elastic deformation in the shallow groundwater aquifers occurs locally in response to injection to RRGI-6.

The indicated leakage to shallow aquifers increases the capability of RRGI-6 to accept injected fluids. The predicted buildup in wellhead pressure after three years of sustained injection into RRGI-6, using 65°C fluid is 1770 kPa at 37.8 lps, 2340 kPa at 50.4 lps and 2906 kPa at 63 lps.

Interference buildup was noted at RRGI-7 in response to the 21 day injection of 37.8 lps to RRGI-6. Apparent interference drawdown responses at RRGP-4 and RRGE-3 in response to the 37.8 lps withdrawals from RRGE-2 are not satisfactorily enough understood to permit potential interference prediction.

With the present pump setting of 245 m, 37.8 lps appears to represent the approximate maximum rate that RRGE-2 can be pumped on a sustained basis for five years.

3. TEST ORGANIZATION

Geothermal fluid was withdrawn from RRGE-2 and injected into RRGI-6 for a period of 21 days in March-April, 1979. The test was organized to permit constant rate, variable head conditions both for withdrawal and injection. The test rate was 37.8 lps. Testing initially commenced March 19th 1979, however after approximately 11 hours had elapsed, equipment failure forced abandonment. After approximately 12 hours recovery, the test was recommenced March 20th and continued until April 10th, 1979. Following the 21 days of testing, recovery observations were recorded for a further 21 day period. Figure 1 shows the location of wells and observation points.

3.1 Equipment and Instrumentation

At well RRGE-2 fluids were withdrawn by a vertical turbine pump with intake set at 802 ft below ground level. Injection into well RRGI-6 was by means of 300hp Johnson pump at ground level.

Drawdown was measured in well RRGE-2 by means of bubbler tube, exiting immediately above the pump impeller. Bubbler pressure was monitored through either a 6895 kPag Heise guage or digiquartz pressure transducer. Leaks in the bubbler tube introduced difficulties during testing.

Injection pressure at the RRGI-6 wellhead was monitored by digiquartz pressure transducer.

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Flow rates at wells RRGE-2 and RRG1-6 were monitored on continuous strip chart recorders.

Fluid temperatures at the wellheads of RRGE-2 and RRG1-6 were monitored by Soltec strip chart recorders. A temperature profile was recorded in well RRG1-6 days after commencing the test and two additional profiles were obtained and days after testing ceased.

No bottom hole pressure instrumentation was available for the test.

Observations of head were recorded at wells RRGP-4, RRGE-3 MW1 & MW2 using digiquartz pressure transducers. Water levels were recorded at Monitor wells 3, 4, 5, 6 and 7 by Stevens Type F instruments.

3.2 Warm-up Procedures

100 gpm was injected into RRGI-6 for a period of 2 hours prior to start up of the test. This water was derived by artesian flow from well RRGE-2 and provided pre-test warm-up of boreholes and pipelines.

3.3 Observation Points

During the test wells RRGE-3, RRGP-4 and monitoring wells 1, 2, 3, 4. 5, 6 and 7 were observed.

4 TEST RESULTS

4.1 Test Rates, Duration and Interruptions.

Well RRGE-2 was pumped at 600 gpm and well RRGI-6 was injected at 600 gpm.

The test was initially commenced on March 19th 1979. On March 20th after 665 elapsed minutes of pumping, mechanical failure caused the test to be aborted. The wells were permitted to recover for 610 minutes and the test re-commenced at 11:34 on March 20th, 1979. The test continued for 21 days until April 10th, 1980. One interruption occurred for a period of 7 minutes on March 27th after approximately 10,000 elapsed minutes in the test. The interruption was caused by electrical overloading by lightning, after 14 elapsed minutes the pumping rates of 600 gpm were re-established at both wells.

interrupted
pumping.

4.2 RRGI-6 RESPONSE

Although the initial test attempt, March 19th was only 665 minutes in duration, the information has been included for comparative purposes in both buildup and falloff responses.

4.2.1 BUILDUP RESPONSE RRGI-6.

The initial test attempt on March 19th included 680 minutes of buildup data and 610 minutes of recovery data. Pertinent information is summarized:

a) initial condition:
warmup flow into the well at 100 gpm; initial wellhead temperature 200°F; initial wellhead pressure 48.6 psia

b) injection rate:
600 gpm stabilized rate after 3 minutes maintained for a duration of 680 minutes.

c) maximum buildup:
202 psia after 680 minutes.

d) final wellhead temperature:
274°F maintained in quasi equilibrium for the final 300 minutes of buildup.

Buildup response and wellhead temperature are shown on the semilog plot in figure 1. It is evident in this figure that wellhead temperature did not stabilize until approximately 350 minutes had elapsed. Wellhead pressure reflects temperature-induced density changes during this initial period resulting in a non-linear shape for the early buildup curve. Late buildup data describes a straight line with slope of 17.2 psi/log cycle.

Pertinent buildup data for the sustained 21 day test is summarized:

a) initial conditions.
   - warmup flow of 100 gpm into the well uninterrupted for 30 minutes prior to startup.
   - initial wellhead temperature 220°F.
   - wellhead pressure was slowly declining prior to testing at a rate of 0.3 psi/minute. A value of 67.5 psia is accepted as initial wellhead pressure.

b) injection rate:

   the rate of 600 gpm stabilized after approximately 3 minutes and remained constant thereafter with the exception of one interruption after approximately 10,000 elapsed minutes. Pumping ceased for a period of 7 minutes and a total of 14 elapsed minutes were required to re-establish a stabilized rate of 600 gpm

c) maximum buildup:

   226 psia after 21 days.

d) well head temperature:

   after approximately 500 minutes, wellhead temperature reached quasi-equilibrium at approximately 274°F. During the remainder of the test, wellhead temperature apparently deviated within a range of 4°F, (272-274°F.).

Buildup response and wellhead temperature are shown on the semilog plot in figure 3. Several linear segments are evident in this figure. In the initial 70 minutes of injection, well head temperature increased by 10°F and the time-buildup curve is linear with a slope of 27 psi/log cycle. The time required to displace one casing volume in RRGI-6 is approximately 20 minutes and it might be argued that the initial twenty minute period represents useful data because the original casing volume was in quasi-stable thermal equilibrium and the injection zones had been "pre-heated" during the initial aborted 11 hour test.

Between 70 and 200 elapsed minutes, both the pressure and temperature at wellhead increased rapidly in non-linear form. Temperature rose abruptly after 100 elapsed minutes, reflecting transmission time through the pipeline from RRGE-2 to RRGI-6. The greatest thermal change occurred between 100 and 200 elapsed minutes; during this period wellhead pressure rose correlatively in response to the decreased density of the hotter borehole volume.

Between 200 and 1000 elapsed minutes, fluid temperature fluctuated by approximately 10°F. At extant densities, this order of fluctuation could result in a range of 5-8 psi at wellhead. For this reason, the apparent straight line segment between 200 and 1000 elapsed minutes is not considered to be representative for analysis.

Between 1,000 minutes and the termination of test, fluid temperature was reasonably constant within the range 272 & 274°F. After 10,360 minutes, the test was interrupted, and approximately 14 minutes elapsed before the injection rate of 600 gpm was re-established. Two linear segments are evident in the time-buildup curve during the late test period. A change in slope is recognized after approximately 8000 minutes. This inflection point occurs only 2000 minutes before the interruption in the test introducing some uncertainty as to whether the inflection represents hydrologic boundary influence or deviation in response to the interruption. The deviated data maintains a linear trend for the final 14 days of the test; in view of the length of this period versus the relatively short 14 minute interruption, it is considered more likely that the late deviated data represents hydrologic boundary influence rather than response to interruption.

RRG1-6 RESPONSE (SUSTAINED TEST) FALLOFF.

Wellhead pressure recovered to apparent initial shut-in pressure of approximately 68 psia after a recovery period of 5000 minutes (3.5 days). This represents a ratio of elapsed times of 7.

The apparent well head pressure of 68 psia does not represent full recovery because the initial shut-in pressure was measured with 100 gpm warm-up flow entering RRG1-6.

Falloff data plotted against ratio elapsed times is shown in Figure 4. It is evident in this figure that only the late falloff data approaches straight line configuration after a ratio of elapsed times of 100 (284 elapsed minutes of falloff.)

Early falloff data is non-linear. This is interpreted as reflecting the effects of slowly decreasing temperature. As the fluid in the borehole slowly cools, its density increases marginally tending to reduce pressure measured at the wellhead. Fluid in the reservoir will experience a reduction in temperature during falloff as a result of heat exchange between fluid and reservoir matrix at the lower velocities which prevail during falloff. The resulting marginally higher fluid viscosities and the resistance to flow will be reflected in higher well head pressure measurements and delayed recovery time.

From this reasoning it is interpreted that the early falloff data will be least influenced by either density or viscosity changes and may therefore be most representative of reservoir matrix characteristics under-pseudo-stable conditions of density and viscosity. The falloff data shown in Figure (4) is for the above reasons analyzed as comprising three segments.

The initial segment between pump shut-off and ratio elapsed times of approximately 1000 (elapsed falloff time of 30 minutes) is accepted as pseudo-stable fluid conditions. During this period wellhead temperature cooled by approximately 8°F. (261 - 253 °F).

INSERT

The wellhead temperature reduction toward ambient wellhead conditions will be much more rapid than temperature changes in the borehole at the injection zones.

INSERT

An intermediate segment is recognized between ratio elapsed times 1000 and 100 (elapsed falloff time 30 minutes to 284 minutes). During this interval wellhead temperature cooled by approximately 53°F (253° - 250°F). In this time interval both the density and viscosity of the fluid are changing significantly but the changes cannot be satisfactorily identified without bottom hole pressure and temperature information. This segment of the falloff data is considered not analyzable.

The Late falloff data after ratio elapsed times of 100 (elapsed falloff time of 284 minutes) describes a reasonably straight line in Figure (4) with markedly increased slope. During this period of time (approximately 3 days) wellhead temperature cooled by approximately 150°F (250° - 100°F). The residual buildup remaining at the beginning of this segment was approximately 40 psia. The influence of increasing density in the borehole fluid is probably a ~~very~~ significant influence on wellhead pressure during this segment of the falloff data rendering it difficult to analyze

4.3 RRGE-2 RESPONSE

4.3.1 The initial attempt to test on March 19 provided 646 minutes of drawdown data and 460 minutes of recovery data. Pertinent data is summarized.

Initial Conditions:

Well RRGE-2 was free-flowing artesian at 100gpm for (?) hours prior to testing to provide preheating. Under these conditions initial wellhead pressure was 450 psia (bubbler pressure).

Maximum drawdown:

Bubbler pressure reduced to 257psia after 646 minutes pumping representing 193 psia drawdown.

Temperature Fluctuation:

Before testing, wellhead temperature was 272°F, it rose to 283°F at the end of the test attempt.

Time-drawdown data for the initial attempt is summarized on the semilog plot in figure 5. Wellhead temperature before testing was 272°F; it reached quasi stability at 282-283°F after approximately 100 elapsed minutes. The early data up to 100 minutes on figure 5 is probably influenced by unstable temperature. The drawdown data between 100 and 646 minutes describes a straight line and appears to represent useful data for analysis.

4.3.1 (Cont'd)

Measurement difficulties with both temperature and pressure instrumentation introduce questionable reliability to drawdown data in RRGE-2 during the sustained 21 day test. Wellhead temperature records on the Soltec strip chart are erratic for the first three days of the test; during the remainder of the test, wellhead temperature appeared to stabilize at 282°F. Bubbler pressures measured by automated digiquartz recorder become erratic and unreliable after approximately 1800 minutes. Manually recorded Heise guage bubbler pressures are less erratic during late drawdown but are less accurate. The erratic late drawdown pressures probably result from inadequate nitrogen purging or leakage in the bubbler line. and

Time-drawdown behavior is shown measured by automated digiquartz in figure 6 and by Heise guage in figure 7. The marked inflection and change of slope occurring after 300 elapsed minutes is attributed to stabilized temperature in the borehole, the data between 300 and 1800 minutes describes a straight line and appears to represent useful data. Heise guage pressures in late drawdown (figure 7) provide a similar slope-rate-of-drawdown although displaced in absolute pressures.

4.3.2 RRGE-2 RECOVERY RESPONSE.

Recovery measurements following the initial test attempt on March 19th are shown plotted against ratio-of-elapsed times in figure 8. Inadequate nitrogen purging of the bubbler line renders early recovery data unreliable. Late recovery data provides a relatively straight line segment however wellhead temperature cooled by 12°F during this period and the wellhead pressures are probably influenced by density changes in the borehole.

Measured bubbler recovery versus ratio elapsed times for the sustained test are shown in figure 9. Fluids reached surface after 15 minutes (ratio elapsed times 2000) This segment of the data is non-linear on figure 9, it may be influenced by frequency of nitrogen purging of the bubble line and vapour compressibility in the wellhead occurring after the venting ports were shut in. This segment of data is not considered reliable for analysis. The data segment between ratio elapsed times 2000 and 50 (initial 10 elapsed hours of recovery) describes a relatively straight line on figure 9. During this period wellhead temperature cooled from 282°F to approximately 200°F. The measured wellhead pressure during this period can be expected to be influenced by changing density in the wellbore. The interval of the borehole open to significant temperature variation during early recovery is that portion dewatered during pumping, or a depth of approximately 440 feet, below this depth the fluid column is presumed to be in relatively stable temperature equilibrium at approximately 282°F.

The relatively short (440') column of fluid anticipated to undergo greatest temperature change in the initial 10 hours of recovery will introduce relatively small density-induced pressure correction. The order of correction is approximately 2 to 2.5 psi. The recovery data between ratio elapsed times 2000 and 50 may therefore be representative for analysis.

Late recovery data, after ratio elapsed times 50, provides non-linear plot on figure 9. Significant time has elapsed after pumping stopped in this segment of the data and wellhead pressure may be influenced by temperature-induced density changes throughout the entire borehole. These influences cannot be satisfactorily corrected without accurate downhole temperature information. For this reason, the very late recovery data is not representative for analysis

4.4 OBSERVATION WELL RESPONSES

4.4.1 RRG1-7 RESPONSE

RRG1-7 exibited anomalous behaviour during did following the test period, evidently in response to injection to RRG1-6. During the initial week of the test, wellhead pressure at RRG1-7 oscillated by approximately 0.2 psi in response to unidentified external influences. During the final two weeks of the test, wellhead pressure at RRG1-7 increased steadily, reaching a buildup of 1.68 psi at the end of the injection period. Wellhead pressure continued to build for 12 hours after injection ceased at RRG1-6, reaching a maximum buildup of 1.77 psi. The well did not recover satisfactorily following the test; a residual buildup of 1.0 psi remained. Wellhead pressures, measured for a further two-week period oscillated by approximately 0.15 psi, again evidently in response to unidentified external influences.

The residual unrecovered buildup cannot be attributed to barometric influences; possible explanations include as yet unidentified external loading or severely delayed recovery from low permeability regions or aquifer deformation.

Uncorrected time-buildup data is shown on figure 10. The Theis, non-leaky, non equilibrium curve-fitting method is applied because the u assumption is not satisfied, precluding application of Jacob the modified Jacob method.

Late uncorrected buildup data provides a reasonable fit with the Theis non-leaky curve. Standard analysis by this method provides values of 7088 gpd/ft for transmissivity and .0082 for storage coefficient. These values indicate an interference buildup of 20 psi (46.2 ft) in RRGI-7 after five years injection to RRGI-6 at 600 gpm.

~~4.4.2 RRGP-4 RESPONSE.~~

~~Wellhead pressure in RRGP-4 was stable at 139 psia for a period of eleven days between March 1 and March 11th. In the seven days immediately prior to testing however, recorded pressures fluctuated in a range from 134 to 143 psia. There is no apparent explanation for the pressure behaviour, it may represent instrument malfunction.~~

~~In the hour before testing shut-in well head pressure was stable at 148 psia.~~

~~During the initial~~

4.4.2 RRGP-4 RESPONSE

Two weeks prior to testing RRGP-4 remained stable at 139 psia. In the week immediately before testing, March 12 - 18th, wellhead pressure apparently fluctuated in a range from 134 to 149 psia. The pre-test wellhead behaviour is shown in figure 11. No explanation for the erratic wellhead pressure is available. For one hour before testing, shut-in wellhead pressure was stable at 148 psia

During the initial eleven hour attempt to test, RRGP-4 wellhead pressure declined by approximately 0.5 psi. It continued to decline during the 12 hour recovery period following this and during the sustained 21 day test reaching a maximum drawdown of 9.3 psia two days after pumping stopped. Wellhead pressure did not recover during the twenty day period after pumping stopped.

The lack of recovery raises some doubt as to whether the observed drawdown is in fact related to pumping - injection or to some unidentified influence. The uncorrected observed drawdown data has been analyzed by Theis non-leaky curve-fitting technique in figure 12. Best-fit curve-matching assuming non-leaky conditions suggests the influence of a limiting boundary in the RRGP-4 response, effective after approximately 4 days pumping. The apparent boundary results in a doubling of the rate-of-drawdown.

RRGE-3 RESPONSE

In the week prior to testing, wellhead pressure in RRGE-3 was increasing at an average rate of 0.07 psia/day as shown in figure 13.

During the initial eleven-hour test attempt, wellhead pressure declined by approximately 3 psia and continued to decline during both the twelve hour recovery period following this and during the sustained 21 day test reaching a maximum drawdown of 13.2 psia. Wellhead pressure at RRGE-3 recovered by only 1.3 psia during the twenty day period following pumping - injection.

Uncorrected time-drawdown data is shown in figure 14. The Theis non-equilibrium curve-matching technique has been applied to this data as the most appropriate method of analysis. The response suggests multiple boundary influences.

4.4.4 MONITOR WELL RESPONSES

Responses related to the injection at RRG1-6 are evident in Monitor wells 4, 5, 6 and 7. Two types of response are identified; positive and negative water level changes. Prior to testing, monitor well water levels were rising at an average rate of 0.01 m/day in a defined trend. Monitor well 4 deviated positively from this trend by approximately 1.22 m as shown in figure 15. Monitor wells 5, 6 and 7 deviated negatively from the pre-testing trend by approximately 0.15 m or less as shown in figure 16. The amplitude of negative deviation in monitor wells 5 6 and 7 reflects the degree of barometric efficiency of these wells, suggesting that the response is probably due to elastic deformation of aquifer matrix by dilation. Monitor wells 5, 6 and 7 recovered following injection.

The positive change in water level in Monitor well 4 indicates that more direct hydraulic communication exists between this well and RRG1-6. Monitor well 4 showed a delayed recovery following injection; the degree of recovery cannot be satisfactorily assessed because irrigation withdrawals from the shallow groundwater aquifers commenced about this time significantly influencing monitor well water levels.

5. DISCUSSION OF TEST RESULTS

5.1 ANALYTICAL METHODS:

In wells RRGI-6 and RRGE-2 it has not been possible to calculate storage coefficient values. For this reason, and because fluid characteristics influence apparent transmissivity values, predictions using standard Theis techniques are not practical.

The method employed is extrapolation of slope-rate-of drawdown or buildup using calculated values of kh to predict slopes for the range of rates and temperatures considered.

kh values have been calculated using the following relationship (Allman, et al, 1979) :

$$kh = \frac{5759\ Q}{s_{10}}\ \mu$$

where :

kh is in md-ft.

Q/s_{10} is in gpm/cycle

μ is in centipoises.

5.2 SUMMARIZED HYDRAULIC PROPERTIES

Table 1 summarizes values of S_{10} and Q/S_{10} for well RRGI-6. Late buildup data in the initial test attempt and intermediate-time buildup data in the sustained test probably provide the most reliable Q/S_{10} ratios with which to calculate kh values. The average of these two is 36.8 gpm/psi/log cycle. representing a kh value of 42,386 md-ft.

Table 2 summarizes values of S_{10} and Q/S_{10} for well RRGE-2. Late drawdown data in both the initial attempt and in the sustained test show reasonable agreement in Q/S_{10} ratios, averaging 10 gpm/psi/log cycle. This represents a kh value of 11,518 md-ft.

Table 3 summarizes values of transmissivity and storage coefficient calculated from apparent pressure responses at RRGE-3, RRGP-4, RRGI-7 and distance drawdown relationship between Monitor wells 2 and 4.

5.3 PREDICTED BEHAVIOUR - WELL RRGE-2

In predicting future behaviour of well RRGE-2 it is assumed that no further hydrologic boundaries will be encountered, no interference influences from either pumping or injection at other centres will be experienced and produced fluid will remain relatively constant at approximately 284°F. For predictive purposes it is also assumed that the pump will be set at 800 ft below ground level and required longevity of the resource is 5 years.

At a producing rate of 600 gpm wellhead bubble pressure would be reduced to 35 psia after five years. This represents the approximate maximum rate that the well can be pumped safely with pump setting of 800 feet below ground level.

5.4 PREDICTED BEHAVIOUR – WELL RRGI-6

It is interpreted from the response of RRGI-6 to the present 21 day sustained test that a hydrologic boundary was intersected after approximately one week of injection. The boundary has an apparent recharge influence and has the effect of increasing apparent injectability. The time of appearance of the recharge boundary effect coincides with the time at which Monitor well 4 responded with elevated water level and Monitor wells 5, 6 and 7 displayed probable elastic deformation. For these reasons it is suspected that sustained injection to RRGI-6 may result in leakage to the shallow aquifer system.

The interpreted recharge boundary occurred when wellhead pressure at RRGI-6 reached approximately 220 psia. If the apparent recharge boundary represents escape to the shallow aquifer system, as interpreted, then a wellhead pressure of about 220 psia may represent a limiting criterion to the injection capability of RRGI-6. In this event, the maximum permissible rate of injection can be predicted using density and viscosity values representative of the temperature of the injected fluid, the calculated representative kh value, a maximum wellhead pressure of 220 psia and a working life of 5 years for the well.

5. DISCUSSION OF TEST RESULTS

5.1 Summarized Hydraulic Properties

Table 1 summarizes values for S_{10}, Q/S_{10} and apparent kh for well RRG1-6. Late buildup data in the initial test attempt and intermediate-time buildup data in the sustained test provide the most reliable Q/S_{10} ratios to calculate apparent kh values. The average of these two is 0.34 lps/kPa/cycle representing a kh of 40,266 md-ft.

Late buildup data from the sustained test, interpreted to reflect a recharge influence, provides Q/S_{10} ratio of 0.46 lps/kPa/cycle or kh of 54,710 md-ft.

Table 2 summarizes S_{10}, Q/S_{10} and apparent kh values for well RRGE-2. Late drawdown data in both the initial attempt and the sustained test show reasonable agreement in Q/S_{10} ratios, averaging 0.09 lps/kPa/cycle representing an apparent kh of 11,518 md-ft.

Table 3 summarizes transmissivity and storage coefficients calculated from apparent pressure responses at RRGE-3, RRGP-4 and RRG1-7. The values obtained for RRG1-7 are probably representative. Values obtained from RRGE-3 and RRGP-4 are probably not representative of aquifer properties, they reflect anisotropic behaviour.

5.2 Analytical and Predictive Methods used:

In wells RRGE-2 and RRGI-6 it has not been possible to calculate storage coefficient values. For this reason and because fluid characteristics influence apparent transmissivity values, predictions using standard Theis techniques are not practical.

Extrapolation of slope-rate-of-drawdown is the most reliable means of predicting drawdown in RRGE-2 at the 37.8 lps rate tested.

Prediction of drawdown and buildup at rates and fluid temperatures other than those tested is much less reliable. The ratio Q/S_{10} has been accepted as a parameter of comparison of well performance at Raft River. It has been shown (Allman 1979) that the ratio Q/S_{10} varies with Q and therefore violates a primary assumption of the Theis solution. For this reason the Theis solution may not represent an accurate simulation of reservoir behavior, however it is the most reasonable means available for predicting behaviour.

The method used to predict at rates and temperatures other than those tested is to initially calculate representative kh values (apparent permeability-thickness products) at the temperature (and viscosity) known during testing. The following relationship is used: (Allman et al, 1979)

$$kh = \frac{5759\ Q}{s_{10}} \mu$$

where: kh is in md-ft
$Q/_{s_{10}}$ is in gpm/psi/cycle
μ is in centipoises

The apparent permeability-thickness product obtained is a sufficiently reasonable indication of the intrinsic transmissivity of the reservoir to use for predictive estimates.

Slope rates-of-drawdown (s_{10}) are calculated at the desired, cooler temperatures (higher viscosities) which are anticipated during operational injection to RRGI-6 and used to extrapolate long term buildup. This may be inaccurate if, as Marigold et al (1979) suggest, the characteristics of the in situ fluid govern behaviour during late buildup time, however the planned injection fluid temperatures are cooler than in situ fluids and the resulting buildup estimates will be conservative.

Early buildup behaviour is significantly influenced by density changes in the borehole fluid column and inefficiencies of flow at the wellbore face.

The influence of cooler fluid density in the wellbore on wellhead pressure can be approximated by:

$$P_{tsc} = 6.895\left(P_{tsw} - (\gamma_c - \gamma_w)\frac{D}{144}\right) \quad kPa$$

where:

P_{tsc} = Wellhead pressure, cool water.
P_{tsw} = Wellhead pressure, warm water.
γ_c = Specific gravity, cool water
γ_w = Specific gravity, warm water.
D = depth to injection zone.

The influence of restriction to flow at the wellbore face is more difficult to estimate. An approximation of this "skin" factor is derived from observed behaviour during the present test and the following relationship: (EARLOUGHER, 1977)

$$\Delta p_s = \frac{141.2 \, q \, B \, u}{kh} \, s \quad (psi)$$

where

Δp_s is the pressure change due to skin effect
q is the flow in STB/D
B is the formation volume factor for water RB/STB
u is the viscosity in centipoises
kh is the permeability thickness product in md-ft.
s is the "skin factor"

The information from the present test provides a value for the skin factor, s = 3.42, this is used to derive initial pressure increases for other rates and temperatures.

The predictive equation to describe total buildup pressure is:

$$P_{tsc} + \Delta p_s + S_{10} \log t.$$

5.3 Predicted Well Behaviour

At a producing rate of 37.8 lps, the bubbler pressure in well RRGE-2 would be reduced to 240 kPa after five years sustained pumping. This assumes no further hydrologic boundaries will be encountered, no interference influences from other pumping/injection centres and relatively constant fluid temperature of approximately 140 °C. With the present pump setting of 245 m; 37.8 lps represents the approximate maximum rate that the well can be pumped safely.

It is interpreted from the response of RRGI-6 to the present 21 day sustained test that a hydrologic boundary was intersected after approximately one week of injection. The boundary has an apparent recharge influence and has the effect of increasing apparent injectability. The time of appearance of the recharge boundary effect coincides with the time at which Monitor well 4 responded with elevated water level and Monitor wells 5, 6 and 7 displayed probable elastic deformation. For these reasons it is suspected that sustained injection to RRGI-6 ~~may~~ will result in leakage to the shallow aquifer system.

The interpreted recharge event occurred when wellhead pressure at RRGI-6 reached approximately 1520 kPa. If this event represents escape to the shallow aquifer system, as interpreted, a wellhead pressure of about 1520 kPa may represent a limiting criterion to injectability in RRGI-6. This wellhead pressure would theoretically be exceeded in one day's injection at 37.8 lps if the injection fluid were 65°C.

By permitting leakage to the overlying shallow aquifers to occur, the injectability to RRGI-6 is significantly improved. Under these circumstances, the predicted wellhead pressure in RRGI-6 at selected times is summarized in Table 4 and presented graphically in figure 17. The predictions assume 65°C fluid, no further hydrologic boundaries and no interference.

CALCULATIONS RRGE-2 WITHDRAWAL

Skin pressure estimated at 70 psi. $kh = 11{,}518$ md ft.

$$\Delta p_s = \frac{141.2\, q\, B\, \mu}{kh}\, s \text{ (psi)}$$

$$s = \frac{\Delta p_s}{\frac{141.2\, q\, B\, \mu}{kh}} = \frac{70}{50.8} = 1.38$$

$$\Delta p_s\,(600) = 70\text{ psi} \qquad = 70\text{ psi}$$

$$\Delta p_s\,(800) = \frac{141.2 \times 27428 \times 1.06 \times .19}{11{,}518} \times 1.38 = 93.5\text{ psi}$$

$$\Delta p_s\,(1000) = \frac{141.2 \times 34286 \times 1.06 \times .19}{11{,}518} \times 1.38 = 116.8\text{ psi.}$$

$$P_{tsf} = P_{tsc}\,(.138\text{psi}) - 4.04 \times \frac{2500}{144}$$

$$= 138 + 70 = 208\text{ psi}$$

CALCULATIONS RRG1-7 Buildup.

MATCH POINTS

1. $T = \frac{114.6\ Q\,W(u)}{S} = \frac{114.6 \times 800}{S} = 7088$

$S_{800} = \frac{114.6 \times 800 \times 10^{-1}}{7088} = 1.3$ ft. $\cdot 5.63$ psi

$S_{1000} = \frac{114.6 \times 1000 \times 10^{-1}}{7088} = 1.6$ ft. $\cdot 6.93$ psi.

2. $S = \frac{Tut}{2693 r^2}$

$r^2 = 6.76 \times 10^6$ ft.
$u = 10^{-1}$
$T = 7088$
$S = .0082$

$t = \frac{2693 r^2 S}{T u}$

$= \frac{2.693 \times 6.76 \times 8.2 \times 10^6}{7.088 \times 10^2}$ $21.06 \times 10^4 = 2.106 \times 10^5$

$= 210,600$ m

3. Match Point

$W(u) = 10^{-1}$
$u = 10^{-1}$
$S_{800, 1000} = .56 , .69$
$t = 210,000$

5.4 Interference Effects.

The buildup at RRGI-7 is accepted as response to injection at RRGI-6. This response indicates an interference buildup of approximately 140 kPa after 5 years injection to RRGI-6 of 133°C fluid at 37.8 l/ps. Using the hydraulic properties obtained in this test ($T = 88.2\ m^2/day$, $S = \cdot 0082$) the potential buildup at other rates of injection is shown on figure 18. It is assumed in this prediction that the response at RRGI-7 will be dependent only on the rate of injection to RRGI-6 and will not be influenced by the temperature of the injected fluid.

The apparent responses in wells RRGE-3 and RRGP-4 are not viewed with confidence as justifiable interference drawdowns for the following reasons:

1. Fluid levels did not recover satisfactorily in either well.
2. Fluctuations in wellhead pressure at RRGP-4 prior to testing were recorded over a range equivalent to the apparent drawdown.

In view of the low degree of confidence in these responses, no estimate of possible interference was attempted.

Response in the shallow aquifer system to injection at RRGI-6 should be anticipated. Predicted interference at M.W. 4 is assumed to be dependendent only on the rate of injection to RRGI-6, regardless of the characteristics and temperature of the fluid injected. Using the apparent properties from best-fit non-leaky curve-matching, the predicted increase in fluid level at MW4 is summarized:

INJECTION RATE (lps.)	ELAPSED TIME (years)	BUILDUP (m)
37.8	3	6.
50.4	3	9
63.0	3	11

TABLE 1

Summary of Hydraulic Properties Well RRGI-6

S_{10} (kPa/cycle) (psi/cycle)	Q/S_{10} (lps/kPa/cycle) gpm/psi/cycle	Apparent kh md-m (md-ft)	Source
119 (17.2)	0.32 (34.9)	11,637 (38,180)	Late buildup data, initial test
148 (21.5)	0.26 (27.9)	9303 (30,523)	Falloff data, initial test
107 (15.5)	0.35 (38.7)	12,904 (42,337)	buildup data, intermediate time, sustained test
83 (12.0)	0.46 (50.0)	16,673 (54,700)	buildup data, late time, sustained test
131 (19.0)	0.29 (31.6)	10,537 (34,570)	Falloff data, early time, sustained test
269 (39.0)	0.14 (15.4)	5,135 (16,847)	Falloff data, late time, sustained test

TABLE 2

SUMMARY OF HYDRAULIC PROPERTIES - WELL RRGE-2

S_{10} kPa/cycle (psi/cycle)	Q/S_{10} lps/kPa/cycle (gpm/psi/cycle)	kh md-m (md-ft)	Source
407 (59)	0.09 (10.17)	3391 (11,126)	drawdown, initial attempt.
441 (64)	0.09 (9.38)	3128 (10,262)	recovery data, initial attempt.
290 (42)	0.13 (14.29)	4765 (15,633)	early drawdown, sustained test
421 (61)	0.09 (9.84)	3281 (10,765)	late drawdown, sustained test
331 (48)	0.11 (12.5)	4168 (13,675)	recovery data, sustained test.

TABLE 2

TABLE 1

SUMMARY OF HYDRAULIC PROPERTIES - WELL RR61-6.

S_{10} psi/cycle.	Q/S_{10} gpm/psi/cycle	Kh md-ft.	SOURCE
17.2	34.9		late Buildup data, initial attempt.
21.5	27.9		Falloff data, initial attempt
15.5	38.7		Buildup data, intermediate time, sustained test.
12.0	50.0		Buildup data, late time, sustained test
19.0	31.6		Falloff data, early time, sustained test
39.0	15.4		Falloff data, late time, sustained test

TABLE 1

TABLE 2.

TABLE 2
SUMMARY OF HYDRAULIC PROPERTIES - WELL RRGE-2

S_{10} psi/cycle	Q/S_{10} gpm/psi/cycle	kh. md-ft	SOURCE
59	10.17		drawdown, initial attempt.
64	9.38		recovery data, initial attempt.
42	14.29		early drawdown, sustained test
61	9.84		late drawdown, sustained test
48	12.5		recovery data, sustained test.

TABLE 3

SUMMARY OF HYDRAULIC PROPERTIES - OBSERVATION POINTS

WELL	TRANSMISSIVITY gpd/ft.	STORATIVITY	SOURCE
RRGI-7	7089	.0082	late buildup, non-leaky curve match.
RRGE-3	10,627	.00001	late drawdown, non-leaky curve match hydrologic boundaries evident.
RRGP-4	12,349	.00012	early drawdown, non-leaky curve match before interpreted hydrologic boundary
RRGP-4	6768	.0002	late drawdown, non-leaky curve match after interpreted hydrologic boundary.
SHALLOW AQUIFERS	62,509	.0028	distance drawdown, non-leaky curve match MW 2 and MW 4 after 25 days injection.

TABLE 3

TABLE 3

SUMMARY OF HYDRAULIC PROPERTIES - OBSERVATION POINTS

WELL	APPARENT TRANSMISSIVITY ~~ft²/ft.~~ m²/day	STORATIVITY	SOURCE
PRGI-7	(7059) 87.6	.0082	late drawdown, non-leaky curve match
PRGE-3	(10,627) 131.3	.00001	late drawdown, non-leaky curve match, hydrologic boundaries limited.
PRGP-4	(12,949) 160	.00012	early drawdown, non-leaky curve match before interpreted hydrologic boundary
RRGP-4	(6768) 83.6	.0002	late drawdown, non-leaky curve match after interpreted hydrologic boundary
~~SHALLOW AQUIFERS~~	~~62,509~~	~~.0028~~	~~distance drawdown, non-leaky curve match MW 2 and MW 4 after 25 days injection~~

TABLE 3

TABLE 4

OBSERVATION WELL RESPONSES TO PUMPING/INJECTION

Observation Point	Elevation	Depth	Casing Depth	Distance RRGE-2	Distance RRGI-6	Initial head	Final head	Drawdown /Buildup
RRGI-7	4855	3888	2044	9738	2601			
RRGE-3	4853	5917	4241	7312	3254			
RRGP-4	4838	5427	3526	5335	8750			
MW 4	4828	305	203					
MW 5	4809	152	124					
MW 6	4811	311	280					
MW 7	4836	152	140					

TABLE 4

PREDICTED WELLHEAD PRESSURES, RRGI-6 INJECTION

INJECTION RATE ~~(gpm)~~ (lps)	TEMPERATURE ~~(°F)~~ (°C)	EQUATION FOR PRESSURE	WELLHEAD BUILDUP 1 DAY	1 YEAR	3 YEARS	5 YEARS
~~600~~ 37.8	~~280~~ 138	~~62~~ 427 + ~~36.57~~ 252 + ~~12~~ 83 log t.	940 136.49	1153 ~~167.21~~	1193 ~~172.97~~	1211 ~~175.61~~
~~600~~ 37.8	~~150~~ 65	~~11~~ 76 + ~~79.08~~ 545 + ~~26.97~~ 186 log t.	1209 ~~175.31~~	1685 ~~244.35~~	1774 ~~257.29~~	1815 ~~263.23~~
~~800~~ 50.4	~~150~~ 65	~~11~~ 76 + ~~105.44~~ 727 ~~+ 35.96~~ 248 log t.	1590 ~~230.07~~	2221 ~~322.13~~	2340 ~~339.39~~	2395 ~~347.30~~
~~1000~~ 63	~~150~~ 65	~~11~~ 76 ~~+ 131.81~~ 909 ~~+ 44.95~~ 310 log t.	1965 ~~284.85~~	2757 ~~399.92~~	2906 ~~421.50~~	2975 ~~431.39~~