GL02976-5

# AIR LIFT AND INJECTION TESTING ON RRGI-7
# FROM AUGUST 1, 1978, TO AUGUST 3, 1978

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Water level recovery data were collected following a twelve hour air lift. The flow, as measured by the rate of filling the mud tanks, averaged 510 gpm with only relatively small temporal variations throughout the test. The wellhead water temperature reached 172 °F which suggests a reservoir temperature in excess of 180 °F. The recovery data, as measured by chalk and tape, are plotted in Figure 1. An apparent abrupt decrease in slope, $\Delta s$, from 11.72 to 5.766 ft/log cycle t/t' occurs after approximately 56.5 minutes of recovery, t'. The slope, after 56.5 minutes, is approximately half the slope of that for the previous data. Assuming an ideal homogeneous isotropic, and infinite aquifer, a linear impermeable barrier boundary results in a halving of the slope during recovery in response to the effects of the second recharging image well. Assuming only one real pumping well and one pumping image well resulted during the 12 hours of air lifting, then during the first 56.5 minutes of recovery there would be the effects of one real pumping well, one pumping image well, and one injection image well. Thus, during the initial recovery segment, there is a net effect of one pumping well. During the second linear segment of recovery, there would be one real pumping well, one pumping image well, and two injection image wells. Thus, during the second linear segment of the recovery curve, there is no net withdrawal from the well. The decline of the water level in the well when $t/t' < 4.8$ is presumed to be related to increasing density of the water in the borehole as the water cools. The significance of the changing density on the wellhead water level when $t/t' > 4.8$ is not known, but could significantly contribute to the observed change in the slope of the recovery data. The ratio of $Q/\Delta s$ for the linear data segments $t/t' > 14$ is 103.1 gpm/psi/log cycle t/t'. The large value for $Q/\Delta s$ compared to values from subsequent tests suggests a significant effect of changing borehole water density on the observed depth to water during recovery.

Injection testing using the drill rig pumps began on August 2, 1978. The initial injection rate of 840 gpm continued for 56 minutes. The rate was then changed to 675 gpm for an additional 80 minutes. The final injection rate of 450 gpm continued for 154 minutes beyond the end of the 675 gpm injection period. The injected water had a temperature of 125 °F. The injection rates were decreased because of the limited capacity of the temporary water supply line from RRGE-3. Figure 2 is a semilogarithmic plot of the wellhead pressure data, s, versus the time since injection began, t. During the initial stage of the injection of 840 gpm for 56 minutes, approximately 20 minutes of injection were required before the data plotted as a straight line. Assuming a storage coefficient of 0.0005, and a T of 429.61 gpd/ft, approximately 0.31 minutes would be required for steady-shape conditions to develop at the well ($u < 0.01$). The wellhead pressure increased at the rate of 224 psi/log cycle of time which resulted in a $\Delta Q/\Delta s$/log cycle time of 3.75 gpm/psi/log cycle time. No boundary effects were obvious during the initial 56 minutes of injection.

The second rate of injection extended from 56 minutes to 136 minutes. The wellhead pressure data for the 675 gpm test are plotted on Figure 2. Figure 3 is a semilogarithmic plot of the pressure difference, $\Delta s'$, between the wellhead pressure that would have resulted had the 840 gpm injection continued and the observed wellhead pressures while injecting at 675 gpm versus the time, t', since injection at 675 gpm began. The data followed a linear trend after 40 minutes of injecting at 675 gpm. The slope, $\Delta\Delta s'$, of the linear trend after 40 minutes is 84.53 psi/log cylce of time, t', which results in a ratio of $\Delta Q'/\Delta\Delta s$ of (840-675)/84.53 = 1.95 gpm/psi/log cycle of time. The near halving of the $\Delta Q'/\Delta\Delta s'$ from the value of 3.75 gpm/psi/log cycle time, $\Delta Q/\Delta s$, obtained during the previous 840 gpm injection period suggests that the calculated $\Delta Q/\Delta s$ and $\Delta Q'/\Delta\Delta s'$ values may be dependent on the injection rate and/or hydrologic boundary effects.

The third rate of injection extends from 136 minutes to 290 minutes. The wellhead pressure as a function of time since injection was first initiated are plotted in Figure 2. Figure 4 is a semilogarithmic plot of the pressure difference, $\Delta s''$, between the wellhead pressure that would have resulted had the 675 gpm injection continued and the observed wellhead pressures while injecting at 450 gpm versus the time, t", since injection at 450 gpm began. The wellhead pressure that would have resulted had injection continued at 675 gpm was calculated using the equation predicting the pressure buildup, s, that would have resulted had injection continued at 840 gpm (Figure 2) minus the pressure difference equation for $\Delta s'$ (Figure 3) resulting from injection at 675 gpm. The pressure buildup data, $\Delta s''$, followed a linear trend beginning at approximately 25 minutes and ending at approximately 110 minutes. The abrupt decline in pressure at 20 minutes is caused by a decline in injection rate. The reason for the deviation from the linear trend beyond 110 minutes is not known. The slope of the pressure data is only 8.90 psi/log cycle time which results in a $\Delta Q''/\Delta\Delta s''$ ratio of (675-450)/2.90 = 25.3 gpm/psi/log cycle time.

This ratio of $\Delta Q''\Delta\Delta s''$ is considerably larger than the preceding values of 3.75 and 1.95 gpm/psi/log cycle time (Figure 2 and 3) for $\Delta Q/\Delta s$ and $\Delta Q'/\Delta\Delta s'$. The classical method of step test analysis (Jacob, C. E., Drawdown Test to Determine Effective Radius of Artesian Well, Trans. ASCE, CXII (1947) pp 1047-1064) assumes the ratio of $\Delta Q/\Delta s$ and $\Delta Q/\Delta\Delta s$ to be a constant for each step. Since this is obviously not the case, an analysis for well loss coefficients was not undertaken. The reliability of the calculated values for $\Delta Q/\Delta s$ and $\Delta Q/\Delta\Delta s$ decreases as the number of steps increase. The data obtained for the third step are probably unreliable with the second step data being much less questionable. The first step data are presumed to be reliable.

Wellhead pressures after five years of injection at a constant rate were calculated by extrapolation of the data procured during injection testing and by assuming an initial wellhead pressure of 0 psi. Based on the 840 gpm data, the equation $s = 25.07 + 224 [\log (t) - 1]$ was used to calculate a wellhead pressure of 1239 psi with no interference after injecting five years at 840 gpm. Figure 5 depicts the predicted wellhead pressures after five years assuming no interference as per the left scale and an estimated 100 psi of interference as per the right scale. In the absence of data to the contrary, a linear relationship was assumed to exist between wellhead pressures and the injection rate. The data from the 675 gpm test was used to calculate a wellhead pressure buildup s, using the following equation: $s = 25.07 + 224 [\log (t) - 1] - 16.36 - 84.53 [\log (t') - 1] \approx 8.71 + 139.47 [\log (t) - 1]$, which predicts a wellhead pressure of 764.6 psi after five years. Similarly using the 450 gpm data, the calculated wellhead pressure buildup was obtained using the following equation: $s \simeq 8.71 + 139.47 [\log (t) - 1] - 14.20 - 8.90 [\log (t'') - 1] \simeq 5.49 + 130.57 [\log (t) - 1]$, which resulted in a predicted wellhead pressure of 750.4 psi after five years of injection. These predicted wellhead-injection rate relationships are plotted in Figure 5. The most reliable prediction results from using the 840 gpm data.

Wellhead pressure recovery data were collected following the cessation of injection using the digiquartz recorder and later when well water levels fell below land surface, a tape was used. Figure 6 is a plot of the recovery data using the digiquartz pressure sensor. The slope of the data, $\Delta s$, when $t/t' > 12$ is 18.38 psi/log cycle $t/t'$. The ratio $Q/\Delta s$ has a value of 31.28 gpm/psi/log cycle $t/t'$ assuming an effective injection rate of 575 gpm. When $t/t' < 12$, the slope is believed to have changed from the 18.38 psi/log cycle $t/t'$ because of operations involved in disconnecting the kelly in addition to errors that would result due to trapped gases in the pressure line from the wellhead to the digiquartz pressure transducer. Figure 7 is a graph of the recovery data collected using a tape after the kelly was removed. The slope of the data when $t/t' > 4.5$ is 42.85 feet of water per log cycle which, assuming a borehole fluid temperature of 120 °F, is equivalent to 18.37 psi/log cycle $t/t'$. The values for the recovery slope per log cycle $t/t'$ are essentially identical using the digiquartz data collected when $t/t' > 12$ and for the tape data when $t/t' > 4.5$. This agreement supports the contention that the digiquartz data collected when $t/t' < 12$ did not accurately represent aquifer pressures. In addition, since no observable change in slope occurred after 56 minutes of recovery, which corresponds to a $t/t'$ of 6.18, the boundary or other pressure effects occurring at 56.5 minutes of the 510 gpm recovery data (Figure 1) were probably due to extraneous effects unique to the data collected following air lifting. The upward drift in the recovery data plotted in Figure 7, when $t/t' < 4.5$, is probably due to a gradually increasing temperature of the borehole fluid.

Assuming an effective injection rate of 575 gpm, a recovery rate of 18.38 psi/log cycle $t/t'$ for the recovery following injection suggests a reservoir kh of 63,057 md-ft. This compares to a calculated kh of 208,527 md-ft obtained for the recovery data collected following air lifting (Figure 1) and a kh of 7559 md-ft for the 840 gpm injection test (Figure 2). Since RRGI-7 will be used for injection, conditions during injection testing are presumed to have a greater similarity to conditions that will be encountered while injecting into the well than the conditions during recovery. Thus, greater reliability should be placed on the injection test data than the recovery data for the prediction of wellhead pressures.

During injection step testing, the wellhead pressure increased at RRGE-3 but declined slightly at RRGI-6. Background wellhead pressure data were collected for approximately 150 minutes prior to the initiation of injection. During this period, the wellhead pressure at RRGE-3 declined 0.2 psi whereas no change occurred at RRGI-6. The long-term trends in wellhead pressures at these two wells are not known. An apparent wellhead pressure buildup at RRGE-3 during step injection assuming a constant temporally independent reference pressure is plotted in Figure 8. The apparent pressure increase was 1.17 psi/log cycle time, but could be as great as 1.67 psi/log cycle time assuming a 0.2 psi decline in the reference pressure per 150 minutes. Effects of this magnitude would result in < 10 psi interference while injecting at approximately 575 gpm. The temporally dependent injection rate technically invalidates the estimated interference of < 10 psi, but probably still provides a reasonable estimate. The lack of response at RRGI-6, which is approximately 100 feet closer to RRGI-7 than RRGE-3, indicates reservoir heterogeneity.

## CONCLUSIONS

1. The best prediction of wellhead pressure buildup results using the 840 gpm data as presented in Figure 5.

2. The wellhead recovery data suggest a much larger kh than that obtained from the 840 gpm injection test.

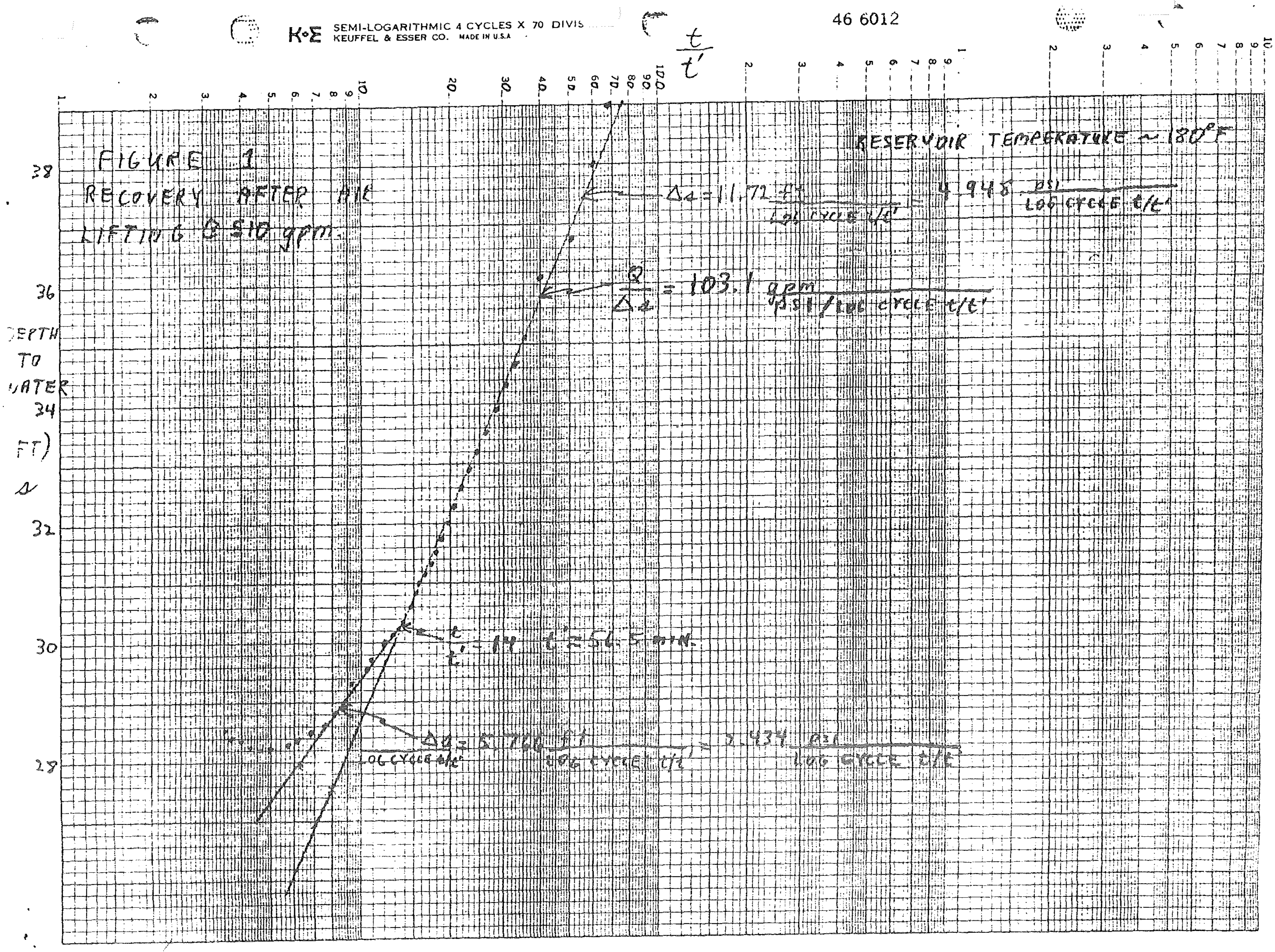
3. Step testing of a well results in calculated values of questionable reliability especially for the third and any other subsequent steps.

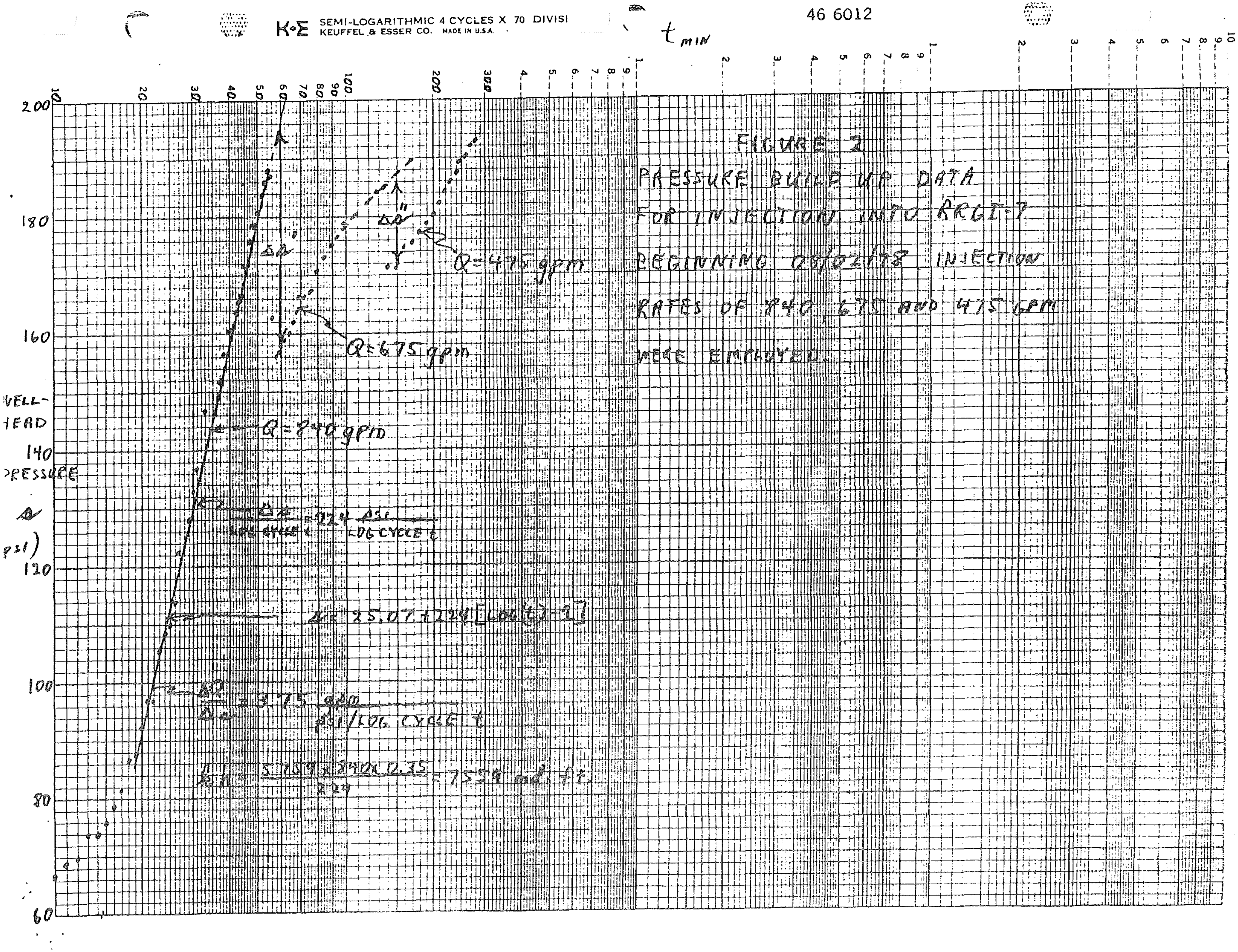
4. Apparent responses occurred in the wellhead pressure at RRGE-3 during injection with no response being observed at RRGI-6. This unequal pressure response indicates a heterogeneous reservoir.

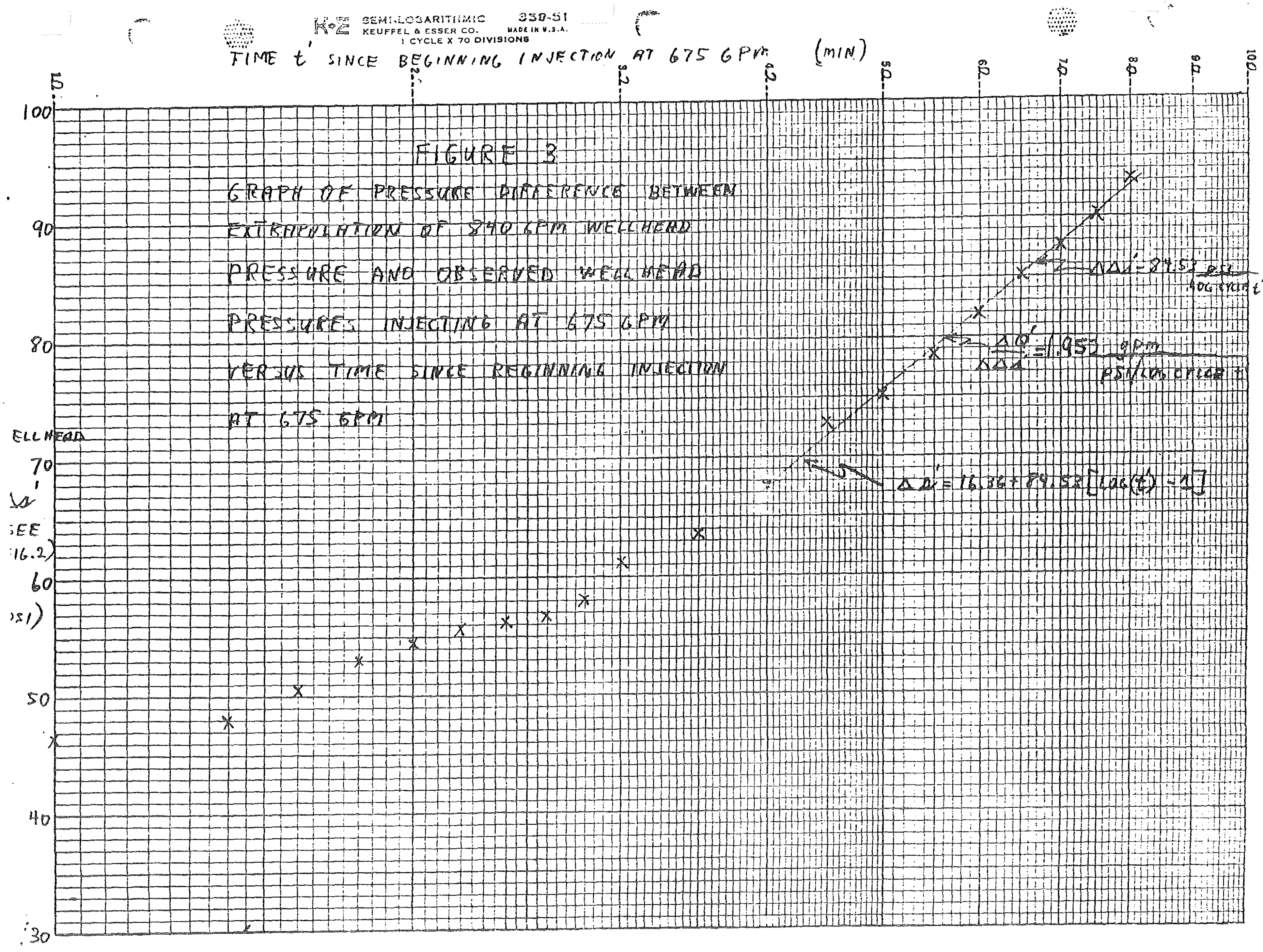
TABLE I

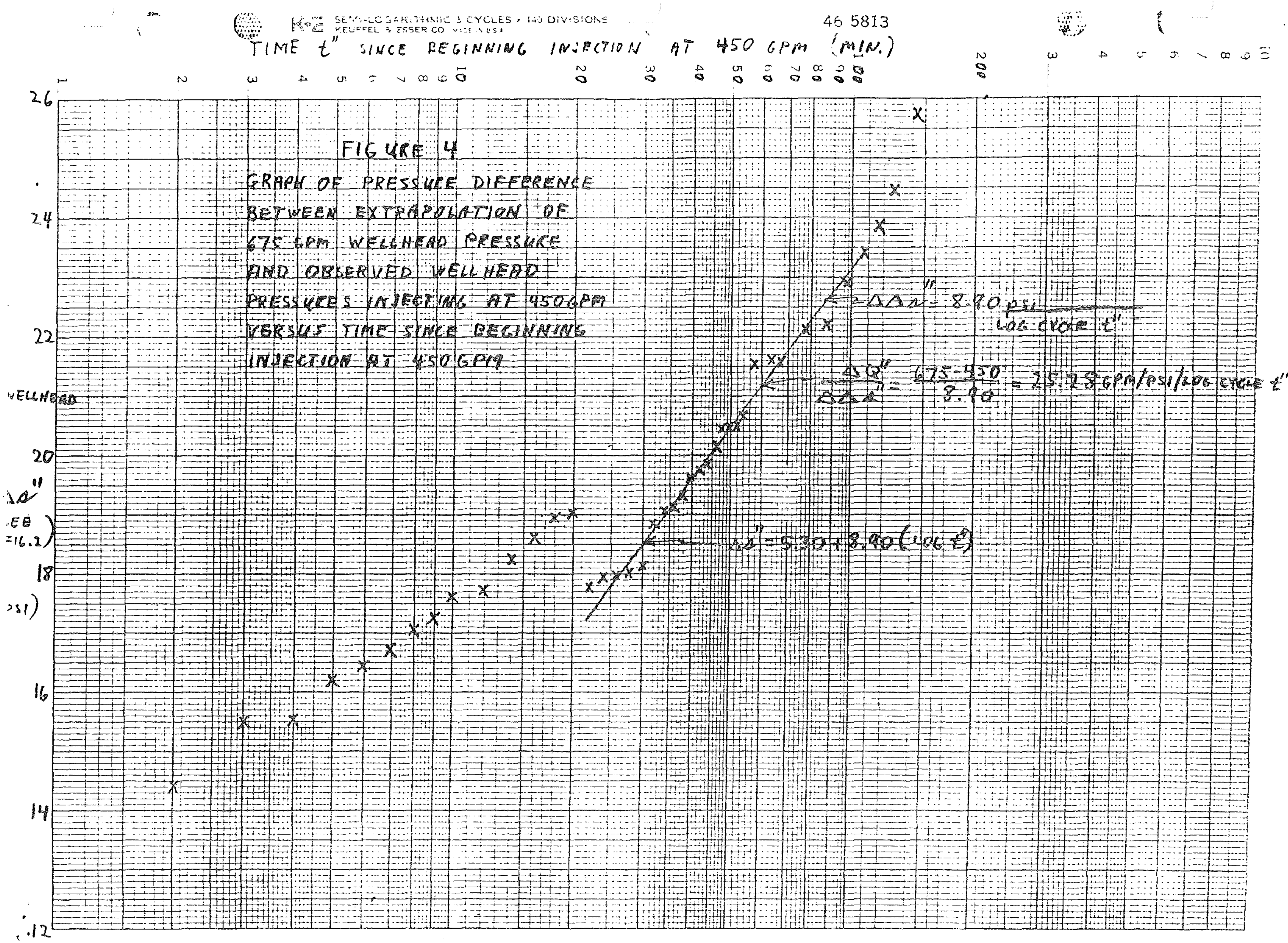
TEST DATA SUMMARY FOR RRGI-7

| | ΔQ (gpm) | Duration (min) | Slope of Data on Semilog Plot (psi/log cycle) | ΔQ/Slope of Data on Semilog Plot (gpm/psi/log cycle) |
|---|---|---|---|---|
| Airlift Recovery | 510 | -- | 4.948 | 103.1 |
| 1st Step | 840 | 56 | 224.0 | 3.75 |
| 2nd Step | 165 | 80 | 84.53 | 1.952 |
| 3rd Step | 225 | 154 | 8.90 | 25.28 |
| Step Recovery | 575 | -- | 18.38 | 31.28 |


K&E SEMI-LOGARITHMIC 4 CYCLES X 70 DIVIS
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 6012
t/t'
FIGURE 1
RECOVERY AFTER AIR LIFTING @ 510 gpm.
RESERVOIR TEMPERATURE ~ 180°F
Δs = 11.72 ft/log cycle t/t' = 4.948 psi/log cycle t/t'
Q/Δs = 103.1 gpm/psi/log cycle t/t'
t/t' = 14 t' = 56.5 min.
Δs = 5.766 ft/log cycle t/t' = 2.434 psi/log cycle t/t'
DEPTH TO WATER (FT)
s
38
36
34
32
30
28


K·E SEMI-LOGARITHMIC 4 CYCLES X 70 DIVISI
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 6012
t MIN
FIGURE 2
PRESSURE BUILD UP DATA
FOR INJECTION INTO RRGI-7
BEGINNING 08/02/78 INJECTION
RATES OF 840, 675 AND 475 GPM
WERE EMPLOYED.
WELL-HEAD PRESSURE (psi)
Q=475 gpm
Q=675 gpm
Q=840 gpm
Δp/LOG CYCLE t = 224 psi/LOG CYCLE t
Δp = 25.07 + 224 [LOG(t) - 1]
ΔQ/Δp = 3.75 gpm/psi/LOG CYCLE t
kh = 5789 x 840 x 0.35 / 224 = 7554 md ft.


K+E SEMI-LOGARITHMIC 359-51
KEUFFEL & ESSER CO. MADE IN U.S.A.
1 CYCLE X 70 DIVISIONS
TIME t' SINCE BEGINNING INJECTION AT 675 GPM (MIN)
FIGURE 3
GRAPH OF PRESSURE DIFFERENCE BETWEEN
EXTRAPOLATION OF 840 GPM WELLHEAD
PRESSURE AND OBSERVED WELLHEAD
PRESSURES INJECTING AT 675 GPM
VERSUS TIME SINCE BEGINNING INJECTION
AT 675 GPM
ΔΔ' = 84.53 psi/log cycle t'
ΔQ'/ΔΔ' = 1.952 gpm/psi/log cycle t'
Δ' = 16.36 + 84.52 [Log(t') - 1]
ELLHEAD
SEE
16.2)
PSI)
100
90
80
70
60
50
40
30



K+E SEMI-LOGARITHMIC 3 CYCLES × 140 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 5813
TIME t" SINCE BEGINNING INJECTION AT 450 GPM (MIN.)
FIGURE 4
GRAPH OF PRESSURE DIFFERENCE
BETWEEN EXTRAPOLATION OF
675 GPM WELLHEAD PRESSURE
AND OBSERVED WELLHEAD
PRESSURES INJECTING AT 450GPM
VERSUS TIME SINCE BEGINNING
INJECTION AT 450GPM
ΔΔs" = 8.90 psi / LOG CYCLE t"
ΔQ" / ΔΔs" = (675-450) / 8.90 = 25.28 GPM/PSI/LOG CYCLE t"
Δs" = 5.30 + 8.90 (LOG t")
WELLHEAD

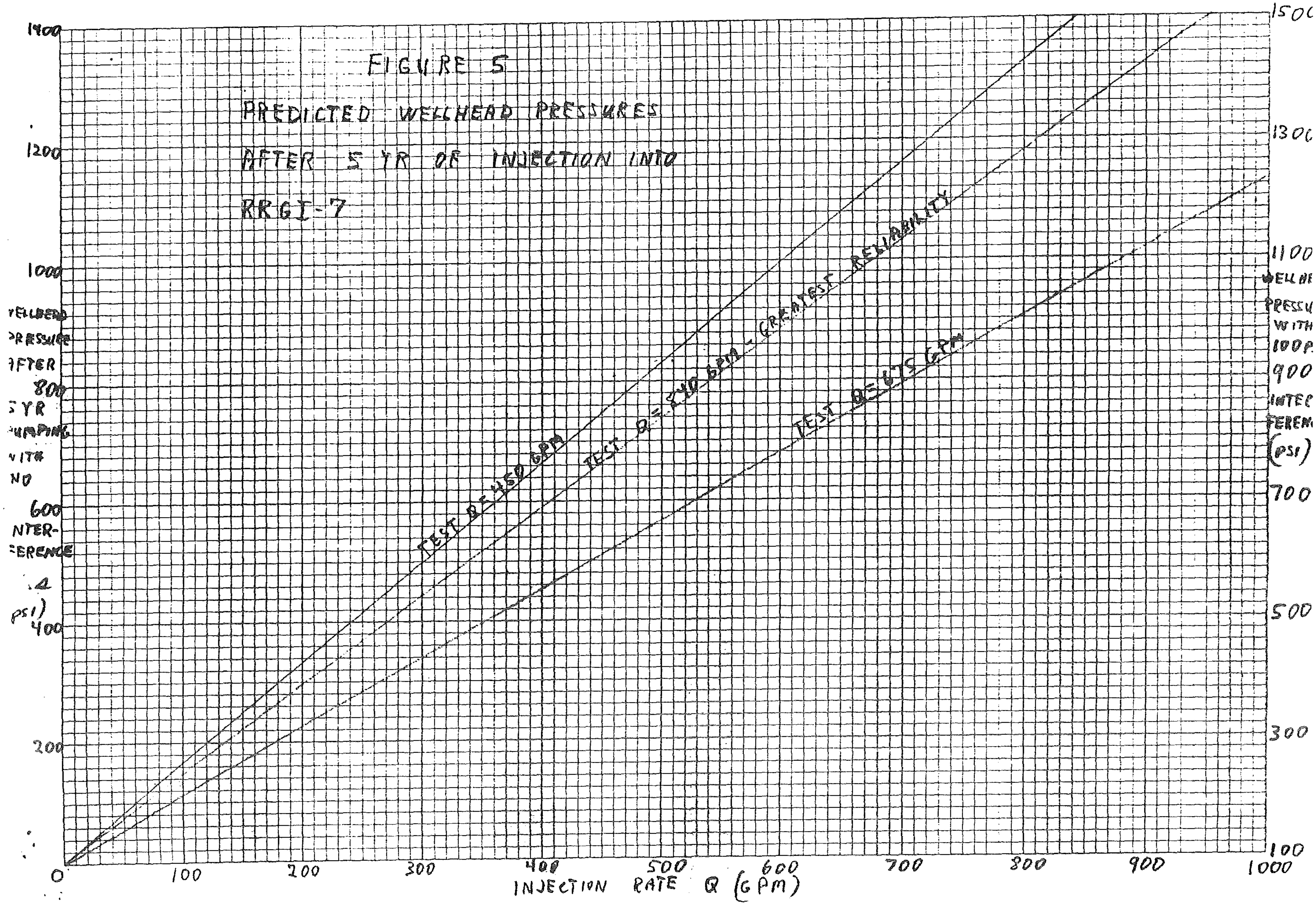


FIGURE 5
PREDICTED WELLHEAD PRESSURES
AFTER 5 YR OF INJECTION INTO
RRGI-7
TEST Q=450 GPM
TEST Q=510 GPM - GREATEST RELIABILITY
TEST Q=675 GPM
INJECTION RATE Q (GPM)
0
100
200
300
400
500
600
700
800
900
1000
200
400
600
800
1000
1200
1400
300
500
700
900
1100
1300
1500
WELLHEAD PRESSURE AFTER 5 YR PUMPING WITH NO INTERFERENCE (psi)
WELLHEAD PRESSURE WITH 100 PSI INTERFERENCE (psi)

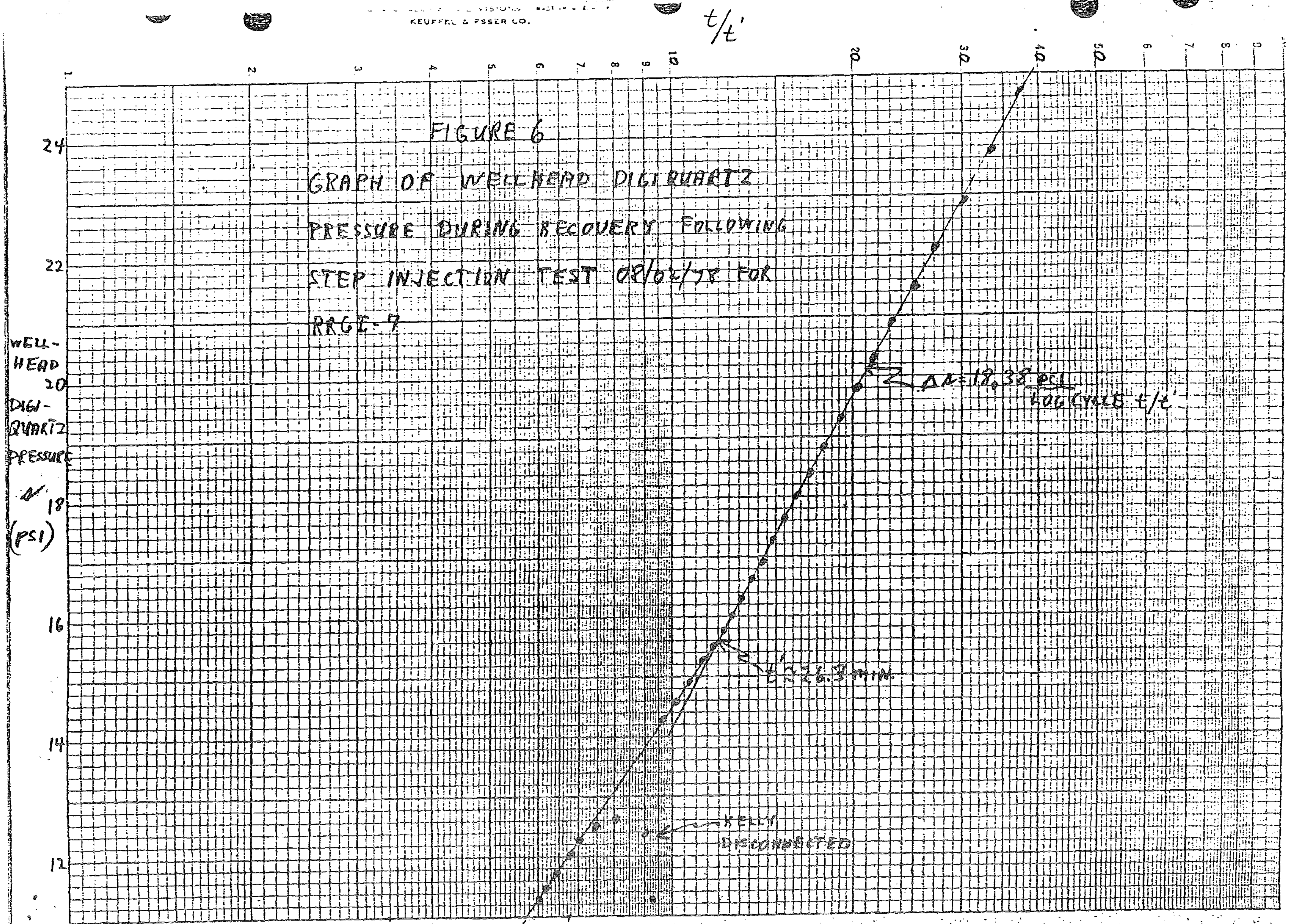



FIGURE 6

GRAPH OF WELLHEAD DIGIQUARTZ PRESSURE DURING RECOVERY FOLLOWING STEP INJECTION TEST 08/02/78 FOR RRGE-7

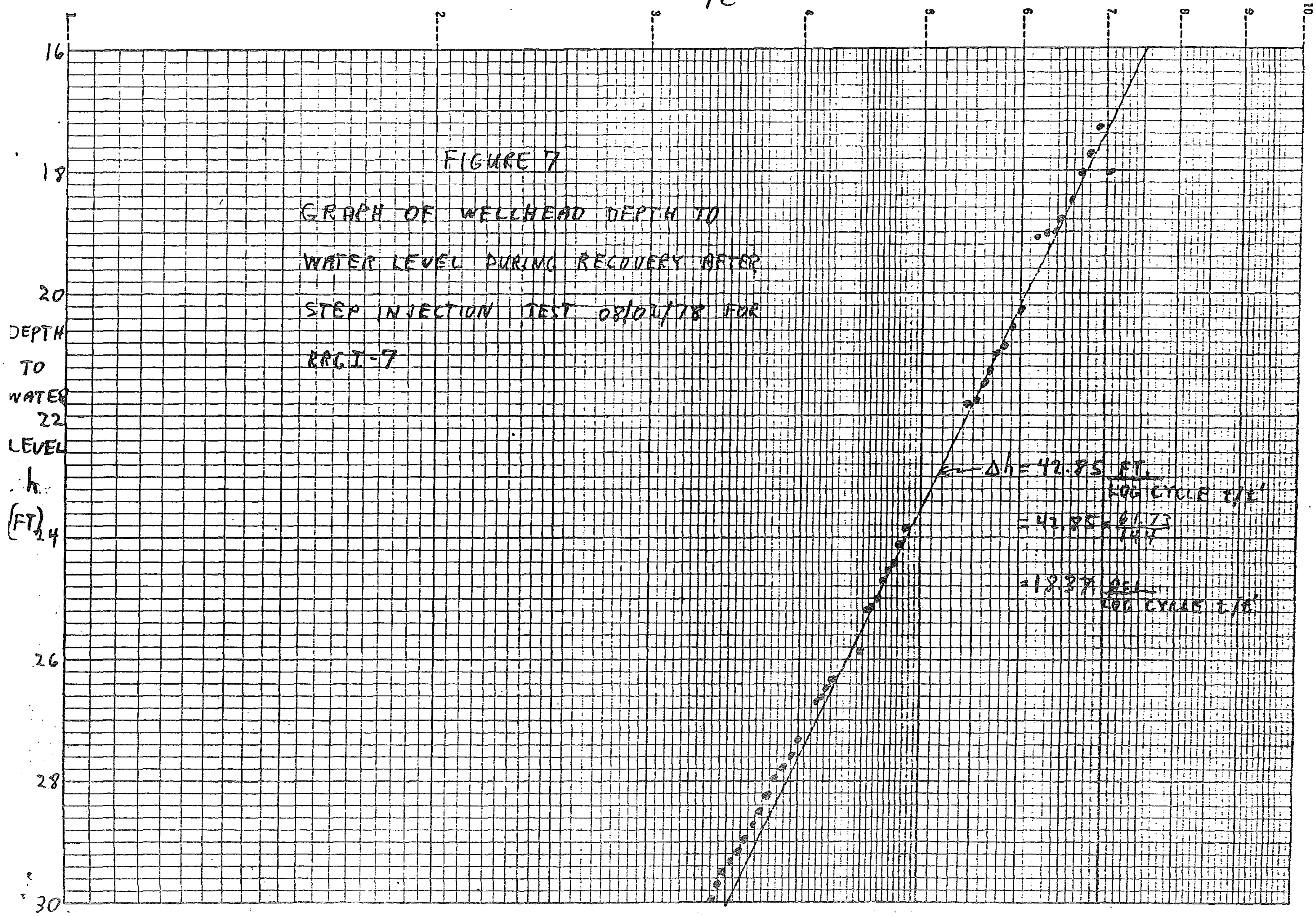



FIGURE 7

GRAPH OF WELLHEAD DEPTH TO WATER LEVEL DURING RECOVERY AFTER STEP INJECTION TEST 08/01/78 FOR RRGI-7

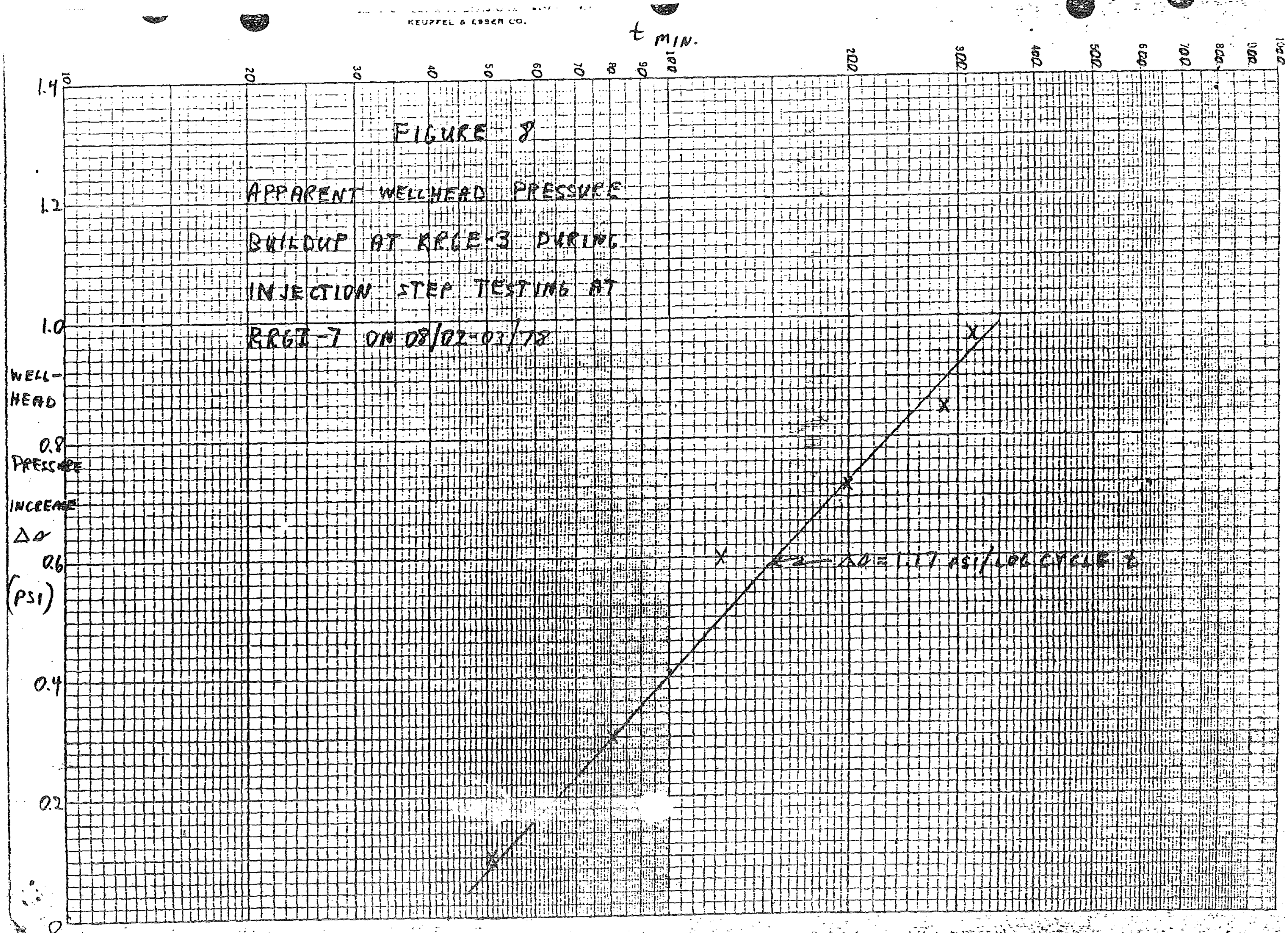



FIGURE 8

APPARENT WELLHEAD PRESSURE BUILDUP AT RRGE-3 DURING INJECTION STEP TESTING AT RRGI-7 ON 08/02-03/78