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EG&G Idaho

INTEROFFICE CORRESPONDENCE

date September 27, 1978

to J. H. Ramsthaler

from R. C. Stoker

subject RRGI-6 INJECTION RATE ESTIMATES - RCSt-52-78

Attached is a paper concerning the data derived from the 800 gpm injection test conducted at RRGI-6 on May 1, 1978. The data is of very short duration (310 minutes or 5.17 hours) when compared to the time desired for estimates (5 years). The test data, and thus the estimates, are subject to change depending on the influence of any undetected hydrologic boundaries which extended testing will detect. The presence of boundaries will generally have an adverse effect on well performance.

Based on the limited test data presented in the attached paper, the following represents the injectability of RRGI-6:

Injection Rate (gpm)	*Wellhead Pressure (after 5 years) (psi)
200	213
300	258
400	305
500	350
600	395
700	440
800	485
900	530
1,000	575
1,100	620
1,200	665

*Add shutin pressure (~ 17 psi) to get gauge reading (psig) at wellhead.

la

Attachment:
As Stated

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FORM EG&G-954
(Rev. 2-77)

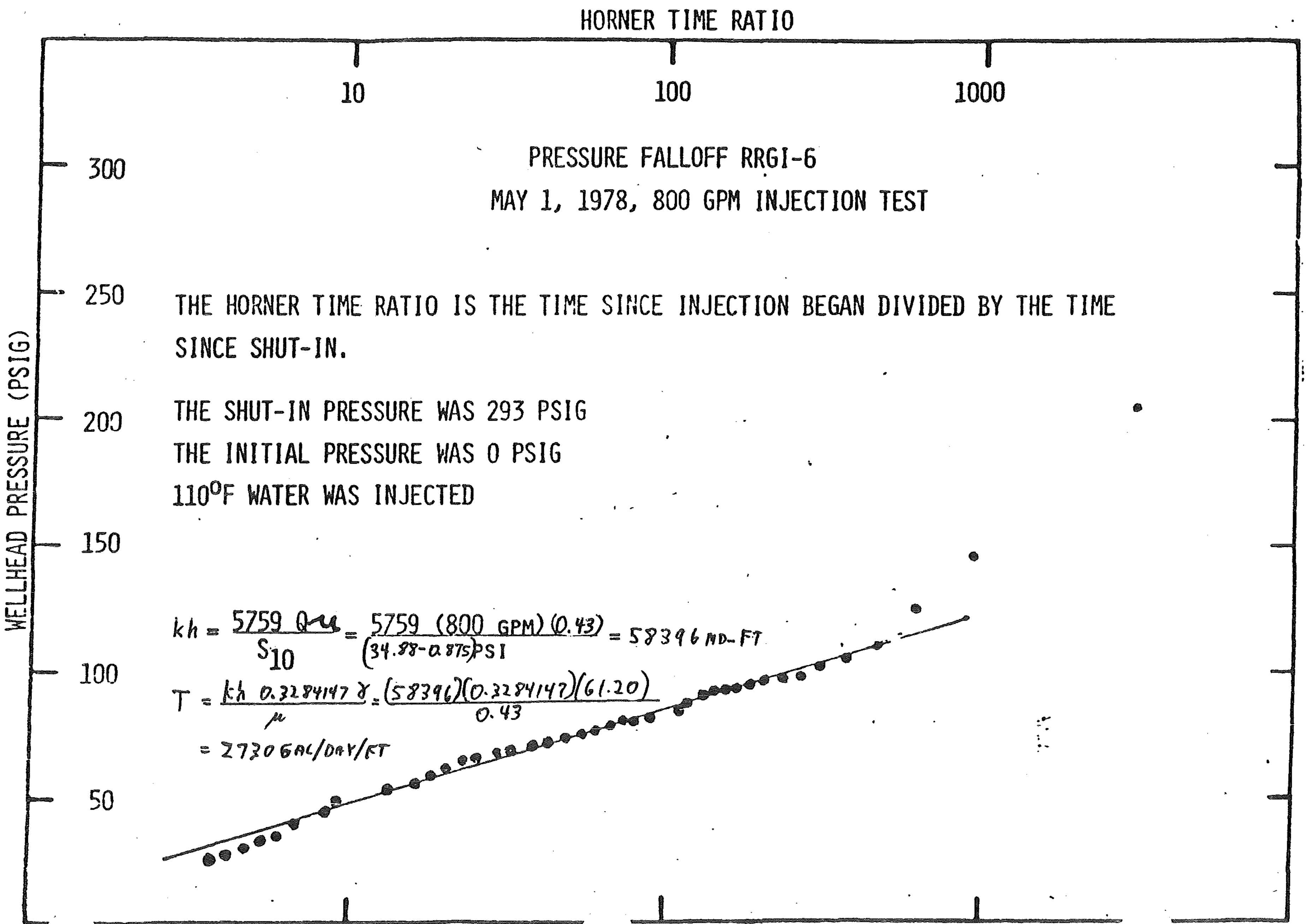
RRGI-6 INJECTION TEST

D. W. Allman

A 3-step injection test and a 310-minute duration injection test was conducted on May 1, 1978. The 3-step injection test data do not yield creditable results and thus will not be discussed in this paper.

The 310-minute duration flow test was conducted at a rate of 800 gpm (Figure 1). A short 6-minute pump failure resulted in a slight deviation of the data collected after 48-minutes of pumping from the linear portion of the data plot beginning at approximately 5 minutes ($u < .01$ after ~ 0.04 minutes). Data toward the end of the test also declined below the preceding linear trend. The reason(s) for this latter departure is not known.

The 110°F temperature of the injected water was lower than the 150°F temperature of the injection zone and resulted in a problem estimating a value for kh. The calculated value for kh is dependent on the viscosity of the waters in the reservoir and the borehole. The viscosity of water at 110°F and 150°F is 0.6145 cp. and 0.4239 cp., respectively. Since the viscosity at 110°F is 45% higher than at 150°F, errors up to 45% in calculated kh values can result because of uncertainties in the viscosity of the waters causing the observed pressure buildup during injection. The temperature distribution of the water in the borehole and in the vicinity of the uncased borehole throughout the injection test is not known, but can be expected to change. This change will result in temporally dependent: (a) well borehole friction losses; (b) turbulent friction losses in the overall receiving reservoir in the immediate vicinity of the borehole; (c) presumed laminar friction losses in the receiving reservoir invaded by the lower temperature injected water; and (d) flow velocities in the wellbore because of



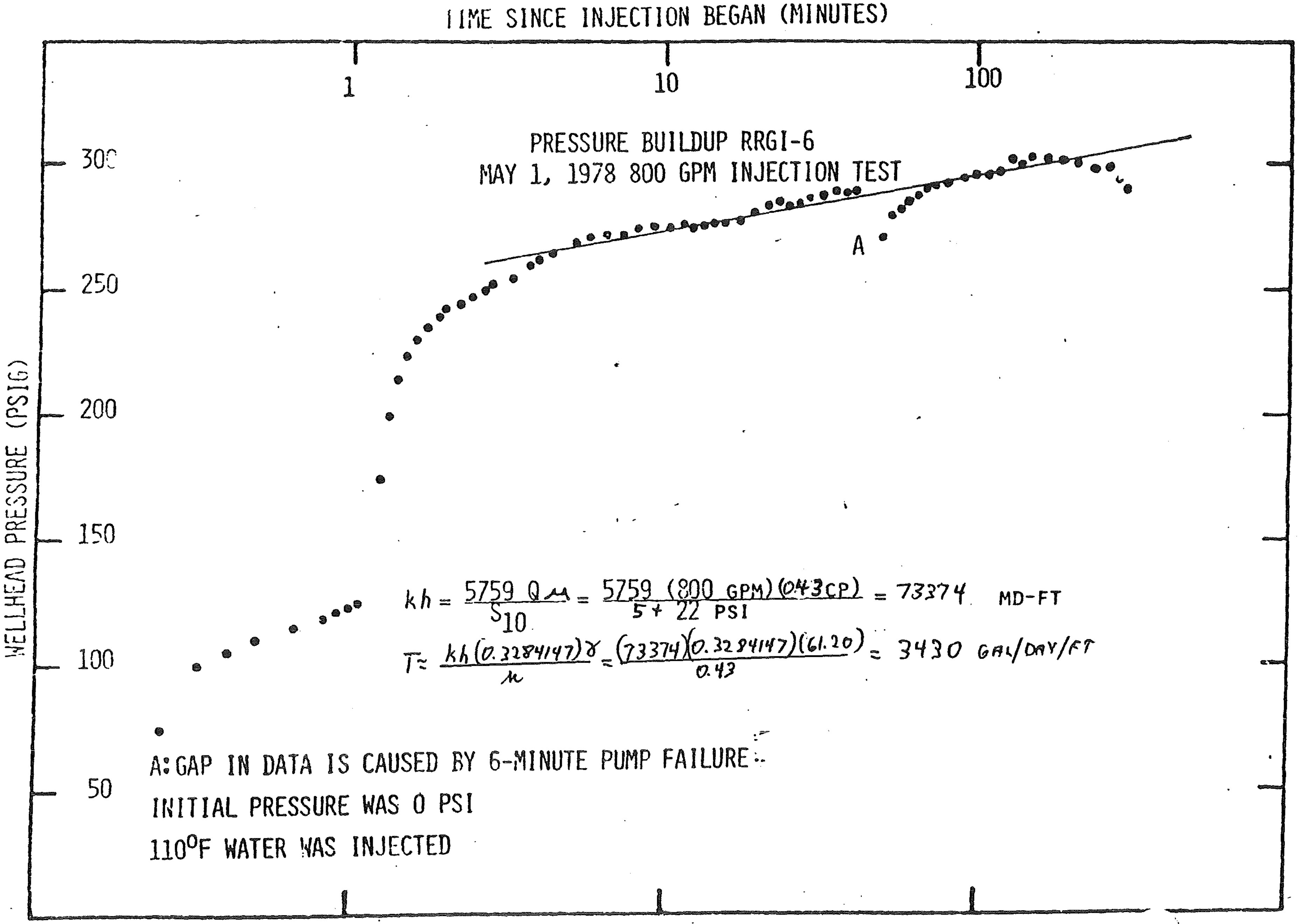
HORNER TIME RATIO
10
100
1000
PRESSURE FALLOFF RRGI-6
MAY 1, 1978, 800 GPM INJECTION TEST
THE HORNER TIME RATIO IS THE TIME SINCE INJECTION BEGAN DIVIDED BY THE TIME SINCE SHUT-IN.
THE SHUT-IN PRESSURE WAS 293 PSIG
THE INITIAL PRESSURE WAS 0 PSIG
110°F WATER WAS INJECTED
WELLHEAD PRESSURE (PSIG)
300
250
200
150
100
50
$kh = \frac{5759\ Q\mu}{S_{10}} = \frac{5759\ (800\ \text{GPM})(0.43)}{(34.88-0.875)\ \text{PSI}} = 58396\ \text{MD-FT}$
$T = \frac{kh\ 0.3284147\ \gamma}{\mu} = \frac{(58396)(0.3284147)(61.20)}{0.43}$
$= 2730\ \text{GAL/DAY/FT}$

differing rates of uptake by the materials having differing permeabilities. Although the wellhead temperature is lower than that in the receiving reservoir, considerable heating of the water would occur while in transit from the wellhead to the receiving reservoir. Assuming that the receiving reservoir is essentially at a depth midway (2786 ft) between the bottom of the casing (1700 ft) and the bottom of the borehole (3872 ft), it requires approximately 22 minutes for the injected water to move from the wellhead to the receiving reservoir, ample time for heating of the injected water to occur. The injected volume during the test was $\sim$14 times the quantity of water contained in the well bore extending from the wellhead to a depth of 2786 ft. However, prior testing also occurred which would have modified the temperature distribution in the well bore and in the receiving reservoir system. Thus, the assumption of the viscosity dependent friction losses remaining constant throughout the injection test is technically invalid with the magnitude of the resulting error in estimating kh being unknown.

A viscosity equivalent to the reservoir temperature was used to estimate kh since it was assumed that, for a short duration test, the greater portion of the time-dependent increase in wellhead pressure would result because of pressure build-up in the receiving reservoir lying outside of the reservoir volume affected by temporally declining temperature. By employing the viscosity corresponding to the reservoir temperature when calculating the kh, conservative (low) values will result compared to those values that would result by employing the viscosity corresponding to the temperature of the injected water. The pressure build-up data in Figure 1 are affected by previous step injection tests which terminated two hours prior to beginning injection at 800 gpm. The pressure build-up curve in Figure 1 would have a slope ~5 psi/log cycle higher than the 22 psi/log cycle observed if there had been no prior injection. The resulting kh is ~73,400 md-ft.

Pressure fall off or recovery data were also collected (Figure 2). A viscosity corresponding to 150°F was also used in the equation to calculate kh. The slope of the linear regression extending from a Horner time rate of 500 to 10 would be ~0.875 psi/log cycle less than the 34.88 psi/log cycle observed if there had been no previous step injection testing. The resulting kh obtained from the pressure recovery data is estimated to be 58,400 md-ft. The log mean kh for the pressure build-up and recovery data is 65,500 md-ft, or a T (coefficient of transmissivity) of 3060 gal/d/ft assuming a temperature of 150°F.

The pressure build-up after injecting for 5 years was obtained by graphical extrapolation using the data plotted on Figure 1. It was assumed that the linear portion of the pressure build-up curve had a wellhead pressure of 275 psi after injecting for 10 min and increased at the rate of 27 psi/log cycle thereafter. No hydrologic boundary effects were assumed to influence the data. After 5 years of injecting at 800 gpm, the calculated pressure would be 421.3 psi at the wellhead. The difference in the specific weights of the water in the well bore during the test (conservatively assumed to be 110°F) and during power plant operation (assumed to be 150°F) would result in a wellhead pressure of 12.4 psi greater than that obtained by graphical extrapolation.



TIME SINCE INJECTION BEGAN (MINUTES)
1
10
100
PRESSURE BUILDUP RRGI-6
MAY 1, 1978 800 GPM INJECTION TEST
A
WELLHEAD PRESSURE (PSIG)
300
250
200
150
100
50
kh = 5759 Qμ / S10 = 5759 (800 GPM)(0.43 CP) / 5 + 22 PSI = 73374 MD-FT
T ≈ kh(0.3284147)γ / μ = (73374)(0.3284147)(61.20) / 0.43 = 3430 GAL/DAY/FT
A: GAP IN DATA IS CAUSED BY 6-MINUTE PUMP FAILURE
INITIAL PRESSURE WAS 0 PSI
110°F WATER WAS INJECTED

FI E 1

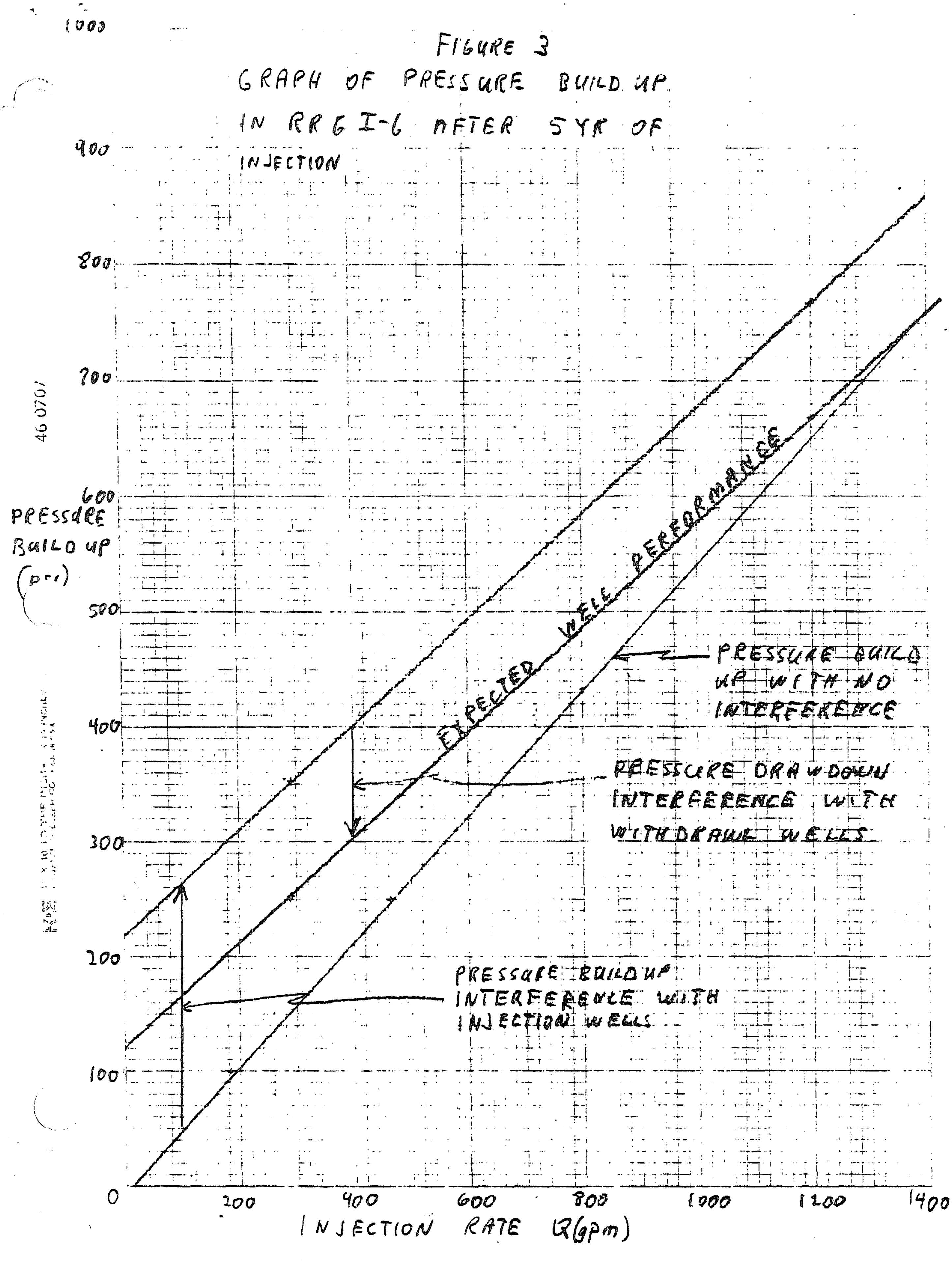
The net resulting wellhead pressure would then be 434 psi. The pressure build-up after five years of injection as a function of injection rate assuming no well interference affects, is indicated in Figure 3. This relationship was calculated assuming pressure build-up to be directly proportional to the injection rate.

Pressure build-up interference will occur between RRGI-6 and other injection wells. To simplify calculations, the remaining portion of the 2500 gpm not injected into RRGI-6 was assumed to be injected into wells at a radius of 2500 ft from RRGI-6. This assumption may not be unreasonable since the radii from RRGI-6 and RRGI-7 and RRGE-3 are ~2500 ft and ~2600 ft respectively. The interference was calculated assuming a kh of 75,000 md-ft, a reservoir temperature of 150°F, and consequently, a T of 3506 gpd/ft. The storage coefficient was assumed to be 5×10^{-4} with interferences being calculated after operating the system for five years or 1825 days. The pressure build-up considering the interference with other injection wells as a function of injection rate is indicated by the upper linear sloping line in Figure 3.

Additional drawdown interference results with the withdrawal wells. To simplify calculations, the withdrawal wells were assumed to be at a radius of 8800 ft which is the approximate distance from RRGI-6 to RRGE-1. The interference was calculated assuming a kh of 75,000 md-ft., a reservoir temperature of 200°F, and a T of 4936 gpd/ft. The storage coefficient was assumed to be 5×10^{-4}. After five years pressure drawdown at RRGI-6 would be 103 psi because of the pumping wells. This pressure drawdown is probably too large because of the higher T in the vicinity of the production wells. The expected well performance curve in Figure 3 considers the interference with both injection and pumping wells.

FIGURE 3

GRAPH OF PRESSURE BUILD UP IN RRGI-6 AFTER 5 YR OF INJECTION



By limiting wellhead pressure to 250 psi, and assuming a pressure build-up of 200 psi and a pressure drawdown of 103 psi, a wellhead pressure build-up of 154 psi would result from injection at the rate of 285 gpm at RRGI-6. Reduced pressure drawdown interference at RRGI-6 would result in an injection rate less than 285 gpm.