PUMP/INJECTION TEST

WELL RRGE-2 TO WELL RRGI-7

August, 1979

by

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LIST OF ABBREVIATIONS

°C	degree centigrade
D.H.P.	downhole pressure
D.H.T.	downhole temperature
°F	degree Fahrenheit
ft	feet
gpd	gallons per day
gpm	gallons per minute
gpm/ft	gallons per minute per foot
HP	Hewlett Packard downhole temperature compensated pressure probe
kPa	kilopascals
lps	liters per second
m	meters
min	minute
m^2/s	square meters per second
N	north
NE	northeast
NW	northwest
perf.	perforations or slots in well casing
psia	pounds per square inch absolute
Q	flow/injection rate
r	distance between pumping point and observation point
S	storage coefficient
s	pressure change
s_{10}	slope of semilog straight line per log cycle
sec	second
T	transmissivity
t	time of flow/injection/recovery in minutes
t^1	time since shut-in
t/t^1	Theis time ratio
t_o	time, since production/injection began, of zero pressure change of the linear extension of the semilog straight line
WHP	wellhead pressure
WHP_H	wellhead pressure utilizing a Heise gauge
WHT	wellhead temperature
W(u)	well function of u

PUMP/INJECTION TEST
WELL RRGE-2 TO WELL RRGI-7

INTRODUCTION

Well RRGI-7, Raft River, Idaho KGRA, was tested by injecting geothermal fluids produced at Well RRGE-2 during August 1979. The purpose of the testing was to evaluate the injection capabilities of RRGI-7 and determine if, through stimulation, the injection capacity could be improved. Data from RRGE-2 was not analyzed in this report.

The specific objectives included:

1. Determine if aquifer inhomogenities occur within the immediate vicinity of RRGI-7;

2. Determine aquifer and well performance during the injection of 93 to 132^{o}C water;

3. Estimate aquifer and well capabilities to receive geothermal fluid produced by RRGE-1, during the upcoming testing of RRGE-1;

4. Estimate RRGI-7 specific capacity and well losses; and

5. Estimate RRGI-7 borehole flow characteristics.

SUMMARY OF RESULTS

The August 1979 test produced data greatly different from that of earlier tests. This is believed to be caused by thermal effects related to the injection of different temperature waters.

Temperature and flow meter borehole geophysical logs recorded by the U. S. Geological Survey during the 96-hour injection test (McCarthy, 1979) were compared with previous logs and the lithology to identify receiving zones within RRGI-7. Groundwater flow within RRGI-7 is apparently through porous sedimentary aquifers, in comparison to fracture controlled flows in other Raft River wells. Predictions based upon RRGI-7 data may therefore be more reliable than elsewhere in the Raft River KGRA.

The results of the August 1979 injection testing of RRGI-7 were used to predict the wellhead and downhole pressure which can be expected to occur at rates and times associated with the proposed RRGE-1 to RRGI-6 and RRGI-7 test.

The predictions indicate that at least 64.4 lps, the maximum rate of each RRGI-7 pump, could be injected into RRGI-7 over the 21 day long-term test from RRGE-1 without exceeding a wellhead pressure of 3100 kPa. This prediction assumed a constant linear pressure buildup and the injection of water hotter than 93°C. The 28.4 lps 96-hour test data and the ratio technique predicted pressure buildups within 90% of those actually seen at 300 minutes into the pulse tests and at shut-in of the 39.1 lps pulse test.

Conclusion drawn from the RRGI-7, August 1979 data include:

1. Thermal effects resulting from the injection of different temperature water greatly influence injection well performance.

2. RRGI-7 injectivity is greater than previously thought.

3. Stimulation should not be attempted without further testing and data evaluation.

4. A 96-hour injection test using water at temperatures approximately plant effluent will be necessary to verify predictions.

Test Procedure

The August 1979 injection testing of RRGE-7 was conducted under directions explicit in EG&G Idaho, Inc., Fluids Experiments and Testing, plan number FET-5-79 (Driscoll, 1979). Geothermal fluid was produced from RRGE-2 and injected into RRGI-7. The injection rate was maintained constant through use of an automatic Richer Flow Control Valve at RRGI-7. The injection rate was recorded on a continuous Soltec Strip Chart Recorder. The RRGE-2 production rate was allowed to vary upon requirements for a constant injection rate. The wellhead pressure and temperature were measured at RRGI-7 and RRGE-2. Bubbler pressure was measured at a depth of 610 m. in RRGE-2. A Hewlett-Packard (HP) Temperature Pressure Probe was installed at a depth of 1132 m. in RRGI-7.

The testing consisted of conducting two constant-rate variable-head pulse tests at 47.3 lps on August 9, and 39.1 lps on August 10, and a constant-rate variable-head long duration test at 28.4 lps on August 11-15. RRGE-2 was artesian flowed at approximately 6.3 lps into RRGI-7 for three days preceeding pulse testing, in an attempt to establish isothermal borehole conditions in the wells. The 47.3 lps pulse test was shut-in after 51 minutes of flow/injection due to equipment malfunction and was followed by 198 minutes of recovery. A second 47.3 lps pulse test followed and was conducted for 337 minutes.

The 39.1 lps pulse was conducted for 8 hours and the long term test for 97 hours. Flowmeter and temperature logs were recorded within RRGI-7 by the U. S. Geological Survey during the long term test. Recovery times between test portions are listed in Table 1.

Data Evaluation

Analysis Theory

The nonequilibrium method and the modified nonequilibrium method were utilized in analyzing RRGI-7 injection buildup data. The nonequilibrium method (Theis, 1935) employs a graphic technique of matching a logarithmic (log-log) data graph to a log-log type curve(s) graph for determining aquifer coefficients. The nonequilibrium method does not yield reliable aquifer coefficients when used with production (injection) well data as pressure drawdown (buildup) related to well construction (well losses) translates the data curve from its correct type curve match. The oil industry uses log-log production (injection) well data graphs and curve matching techniques for estimating skin effects and fracture characteristics of the well.

The modified nonequilibrium method (Cooper and Jacob, 1946) utilizes a semilogarithmic (semilog) graph of wellhead pressure or change in wellhead pressure versus the log of production (injection) time. The data graphs as a straight line when the variable of intergration u (Theis, 1935) is less than or equal to 0.01. The semilog graph, from which aquifer coefficients are determined, cannot be used unless u is less than or equal to 0.01. The time required for the u assumption to be satisfied is determined from the formula:

$$t = \frac{r^2 S}{4 Tu} \qquad (1)$$

where

$u = 0.01$

The u assumption is satisfied in less than a minute at well RRGI-7, assuming a transmissivity of 6.3×10^{-4} m^2/s, a storage coefficient of 0.005 and an effective well radius of 0.3048 m.

Conventional aquifer test analysis involves the determination of the aquifer transmissivity and storage coefficient. The transmissivity can be calculated from production (injection) well data or observation well data (assuming the observation well penetrates the same aquifer). Data from observation wells are more desirable because the production (injection) well's pressure influence is integrated over a larger area of the aquifer. Transmissivity can be calculated from the nonequilibrium equation:

$$T = \frac{Q}{u\pi_s} w(u) \quad (2)$$

where:

$w(u)$ is determined from type curves or tables

and the modified nonequilibrium equation:

$$T = \frac{2.3 \quad Q}{4 \quad \pi \quad s_{10}} \quad (3)$$

Production (injection) well data cannot be used to determine the storage coefficient, which can only be estimated from observation well data. The storage coefficient can be estimated from the nonequilibrium equation:

$$S = \frac{4T\ tu}{r^2} \quad (4)$$

where:

u and t are determined by graphical methods and the modified nonequilibrium equation:

$$S = \frac{225\ Tt}{r^2} \quad (5)$$

Equations 1-5 were developed on the basis of the following assumption: The aquifer is infinite in areal extent and is of the same thickness throughout; that it is homogeneous and isotropic; that the temperature of the fluid remains constant throughout the aquifer test; that the well has an infinitesimal diameter and penetrates the entire thickness of the formation; that the aquifer is artesian with an impermeable confining layer; that the confining layer releases no water from storage; and that vertical flow components are negligible. It has been found (Allman and others, 1979) that in geothermal aquifer test at Raft River the assumptions inherent in aquifer test theory are not satisfied. This report uses the ratio Q/s_{10}, which is analogous to transmissivity (see equation 3) to compare and evaluate aquifer tests.

Injection Rates

RRGE-2 was artesian flowed at approximately 6.3 lps into RRGI-7 preceeding the pulse tests, in an attempt to establish isothermal borehole conditions. The preheating is not accounted for in data evaluation due to the erratic nature of flow rate. Variations of injection rates are presented in Table 2.

Receiving Zones

Borehole geophysical logs recorded during the long term test (McCarthy, 1979), and by the U. S. Geological Survey (Keys, 1979) and oil well service companies previous to the test were compared to determine the primary receiving zones within RRGI-7. The receiving zones are summarized in Table 3. The injected volumes could not be estimated due to stalling of the flowmeter below 1000 m. during geophysical logging. All receiving zones are apparently porous sedimentary rocks, with fractured zones currently not identified. Work is in progress on further definition of the receiving zones, and their correlation with receiving zones in RRGI-6 and lost circulation zones in RRGE-3.

RRGE-7 Buildup

The initial and shut-in RRGI-7 wellhead and HP pressures and temperatures are presented in Table 1. The differences in initial pressures and temperatures are related to the amount of preheating and, perhaps, incomplete recovery from the previous phase of testing.

Semilog graphs of the two 47.3 lps pulses (Figures 1 and 2), the 39.1 lps pulse (Figure 3) and the 28.4 lps long term test (Figure 4) show that the wellhead pressure buildup mirrors the change in injection water temperature. The 39.1 lps and 28.4 lps pressure data show an initial linear segment, followed by a sharp increase in pressure, to a second linear trend. It requires approximately the time of the initial linear segment to inject the volume (45,450 L.) of the cased borehole (623 m.) into the well. It is believed that the initial borehole volume is quasi-isothermal. Relatively small temperature changes can be seen to occur during this time. This initial segment, therefore, experiences relatively small viscosity and density effects, and may accurately express aquifer characteristics, assuming no aquifer inhomogeneties. A large portion of the data scatter during the initial segment is caused by variations in the injection rate. The increase in pressure above the initial linear trend is presumed to be caused by the decreasing density and viscosity of the hotter water as injection progresses. The skip in pressure and temperature during the period of rapid pressure and temperature increase, (Figures 3 and 4) is believed related to cooler water in the injection pipline. This hypothesis will be further investigated during the upcoming RRGE-1 test, by inserting temperature probes at various points along the injection line.

A second linear trend becomes apparent in Figures 3 and 4 when thermal quasi-equilibrium is established with stabilization of injection temperature at approximately 127^{o}C. The length of time required to reach the second linear segment depends on the injection rate, and the initial pressures and temperatures. Data scatter in the second linear segment is caused by variation in injection rate and/or aquifer inhomogenities. Differences in slope (s_{10}) between the linear trends is believed to be related to injection rate, rate of thermal changes and the initial pressures and temperatures. The differences in slope require further investigation.

The initial 47.3 lps pulse test (Figure 1) shows the initial linear segment and the thermally affected pressure increase. The data is influenced and interpretation complicated by a poor control of injection rate.

The second 47.3 lps (Figure 2) shows three linear segments. The second segment is believed to be caused by thermal effects. Erratic data after 300 minutes is due to the injection line strainers at RRGI-7 being back flushed.

The HP pressure-temperature probe has been found to be extremely sensitive to temperature changes (Allman and others, 1979). Only very early time qualitative interpretations can be made from the 47.3 lps (Figure 5) or the 39.1 lps (Figure 6) tests due to erratic data. The long term test (Figure 7) data returns to the initial linear trend once the temperature becomes relatively stable. The HP probe malfunctioned after 2800 minutes of injection during the long term test preventing conclusive determination of return to the linear trend. A decrease in injection water temperature can be seen in the HP data, as in the wellhead data.

Log-log graphs of the wellhead and HP pressure buildup, during the 28.4 lps test also show the effect of temperature. Linear data trends, between 20 and 100 minutes on both graphs, and erratic data are caused by pressure increases related to temperature. Curves could not be matched with standard Theis type curves.

Equations by (Papadopulous and Cooper 1967), (Ramey, 1973) and (Schafer, 1978) were used to estimate if wellbore storage affected the early time data. The equations indicated that wellbore storage was a factor for the first 40 to 160 minutes (dependent on which equations are utilized) during the 38.4 lps test. However, it is believed that the pressure responses resembling wellbore storage are influenced by thermal related temporal density changes, as water is virtually incompressible and the wellbore was full before injection began.

RRGI-7 Falloff

Pressure fall-off data at RRGI-7 was analyzed by two methods; the Theis time ratio plot and calculated recovery. The former is a graph of pressure or pressure change versus the log of the time since the start of injection divided by the time since shut-in (Theis time ratio).

The data should graph as a straight line when u is less than or equal to 0.01. The u condition is satisfied during falloff if it was satisfied during injection. Aquifer coefficients are calculated from the modified nonequilibrium equations. The parameter Q/s_{10} is again calculated for falloff (recovery) data. Pressure falloff increased more rapidly than anticipated due to the increasing density of the borehole column as the well cooled. Temperature data was not available at the wellhead during recovery. Borehole temperature profiles, not available, would be more meaningful.

The initial straight line segment of wellhead falloff data for the 47.3 lps pulse shown on Figure 8 perhaps best expresses aquifer behavior because thermal effects are minimal. The shift in wellhead pressure after ratio $t/_{t}1$ of 6.4 is mechanical, related to installation of the HP probe.

Bottom-hole pressure data is available for the falloff portion of the 47.3 lps and 39.1 lps pulse tests but was not available following the sustained 28.4 lps test.

Early bottom-hole falloff data following the 47.3 lps pulse (Figure 9) may be representative because bottom hole temperature is stable during this period. No bottom hole temperature information is available during falloff following the 39.1 lps pulse (Figure 10). For this reason calculated values may be less representative.

Figures 11 and 12 show wellhead pressure response to falloff after the 39.1 lps and 28.4 lps test respectively. These plots were analyzed by the Theis time ratio method. No wellhead temperature information is available to judge the representatives of calculated properties.

Calculated recovery data, a correction for residual pressure buildup should be used with either the nonequilibrium or modified nonequilibrium plots of recovery (t^1). Calculated recovery is plotted versus log shut-in time (t^1) in Figures 13 through 16. The graphs show a linear segment followed by non-linear data, related to thermal effects.

Table 4 lists the shut-in times at which the break from a linear trend to non-linear data was obvious. No relationship between injection rate, shut-in temperature and shut-in time could be determined. Additional studies concerning the problems of thermal effects are required.

A log-log type curve match of calculated recovery data from the 39.1 lps test produced parameters that were 65% of the semilog results for the same data. The variation is caused by the previously mentioned difficulties. No curve match was possible with the 28.4 lps recovery data.

Calculated Q/s_{10} values are summarized in Table 8.

Specific Injectivity

The specific injectivity, the pressure buildup at a given time divided by the injection rate, was calculated for wellhead data, after 10 and 60 minutes of injection. The values are plotted versus injection rate in Figure 17. The log mean specific injectivities for 10 and 60 minutes were 0.085 lps/kPa at well RRGI-6 (Allman and others, 1979b). The 8 and 24 hour specific injectivities were 0.053 lps/kPa and 0.050 lps/kPa for RRGI-7.

Well Losses

Well losses are a portion of the pressure response which occurs when pumping (injecting) a well and are caused by well construction and completion techniques. Well losses do not occur during recovery. Well losses can be estimated by comparing pressure buildup and calculated recovery, comparing drawdowns predicted by the nonequilibrium formula with the actual drawdown or calculating the well-loss constant from a variable-rate test (Jacob, 1946).

Well losses do occur in RRGI-7, and may account for a substantial portion of total pressure buildup (Table 5). It is believed that thermally dependent density changes account for a large portion of the well losses. The comparison of buildup and calculated recovery data usually provides an accurate estimate of well losses. This comparison may yield too high an estimate in geothermal wells due to temporal thermally affected data. Well losses in geothermal wells may be an irrelevant term unless thermal effects are corrected out of the data.

Observation Well Data

RRGI-6, RRGE-3 and MW 3-7 were used as observation wells for the RRGE-2 to RRGI-7 test. Pertinent well construction information is presented in Table 6.

RRGI-6

Wellhead pressure at RRGI-6 apparently rose by approximately 5 kPa as a response to the injection of 28.4 lps into RRGI-7 (Figure 18). The pressure increase was not related to any trend within the aquifer(s) penetrated by RRGI-6 as the wellhead pressure had been decreasing slightly since July 30, 1979. A linear regression was performed on the data between 2000 and 7000 minutes. The results were a coefficient of determination of 0.953, and an equation of wellhead pressure trend equal to 35.14 psia + 0.552 log injection time. Based upon this equation the continuous injection of 28.4 lps into RRGI-7 for 5 years would result in a 55 kPa increase in RRGI-6 wellhead pressure. Interference measured at RRGI-7 during testing of RRGI-6 (Allman and others, 1979b) indicated an increase in wellhead pressure of 97 kPa after 5 years of injection. The differences are apparently greater than can be accounted for by the difference in injection rates. The differences are perhaps related to the more transmissive thief zone seen by well RRGI-6 but not well RRGI-7. The decreasing pressure trend in RRGI-6 was not included in the analysis. The u assumption was not satisfied in the time pressure response was apparent at RRGI-6. Therefore, the nonequilibrium method was attempted to evaluate the RRGI-6 data (Figure 19). It was not possible to obtain a curve match, but the data curve is suggestive of a leaky artesian condition, or a recharge boundary.

RRGE-3

Figure 20 shows that decreasing wellhead pressures occurred at RRGE-3 during the 28.4 lps test. This was not the anticipated response caused by RRGI-7 injection. Possible causes included reservoir dilation, drawdown caused by pumping of RRGE-2, and long term regional water level trends. Relatively stable wellhead pressure occurred between July 25 and August 1. RRGE-3 was produced on August 1 and 3 resulting in an increase in wellhead pressure, caused by the flow of hotter temperature, lower density water into the wellbore. An expected decreasing wellhead pressure occurred after the well was shut-in due to thermal effects. No attempt was made to obtain aquifer coefficients from the RRGE-3 data due to the anomalous data and the differing open hole intervals of the two wells.

Monitor Wells

The MW well data is discussed at length in the quarterly Monitor Well Report (McCarthy, 1979). No obvious responses were readily apparent in any monitor well.

RRGE-2 Response

Graphs of RRGE-2 wellhead pressure versus log production time (Figures 21, 22, 23, 24) could not be quantatively evaluated as the production rate was allowed to vary. The Q/s_{10} value of the 28.4 lps the only graph with a readily apparent linear trend, of 0.2745 lps/kPa/log cycle, is substantially larger than calculated during previous testing (0.1076 lps/kPa/log cycle calculated from a 25.2 lps test). An in-depth analysis of RRGE-2 will be accomplished in a different report.

Discussion of Test Results

The results of the August 1979 testing are summarized in Table 7. The log mean of the Q/s_{10} values was 0.3750 lps/kPa/log cycle which is analagous to a transmissivity of 6.4×10^{-4} m^2/s for RRGI-6 (Allman and others, 1979b). No definite boundaries were apparent in the RRGI-7 data.

The Q/s_{10} values were graphed on log probability paper (Figure 25) to determine the distribution of the data. The coefficient of determination ($r^2 = 0.942$) is indicative of a normal data distribution. The extreme Q/s_{10} values were not used in the calculations of the coefficient of determination. The high Q/s_{10} value, from late time of the 47.3 lps pulse number two, supports the assumption that higher temperature, lower viscosity water has a greater apparent transmissivity. This test had the highest initial wellhead temperature, the most rapid temperature increase and achieved isothermal conditions sooner, relative to other tests. The low Q/s_{10} value cannot currently be explained.

It was thought that recovery data would yield higher values as we expect temperatures to change more slowly than during injection. Early time recovery data may thus yield more accurate aquifer coefficients. Wellhead temperatures during recovery must be recorded during future tests to evaluate this hypothesis.

The Q/s_{10} of a theoretical ideal well and aquifer is constant and independent of Q. As indicated by the low coefficient of determination ($r^2 = 0.115$), Q/s_{10} values are not constant. RRGI-7 pressure buildup predictions may be used with a degree of certainty if the Q/s_{10} is independent of Q and varies within establishable limits. The upcoming RRGE-1 to RRGI-6 and RRGI-7 test will help to evaluate the reliability of RRGI-7 predictions. The 28.4 lps test data and the ratio technique predicted pressure buildup within 90% of those seen during the other test phases.

RRGI-7 Pressure Predictions

Pressure predictions (Table 8) based on the August 10, 1979 test indicate that 69.3 lps of 127°C could be injected into RRGI-7 during a 21-day test without exceeding a wellhead pressure of 3100 kPa. The effect of injecting higher temperature fluid can be seen by comparing the August 1979 predictions with predictions derived from the November 1978 injection test. The injection of cool water, 14.4°C indicated that 20 days of continuous injection of 32.5 lps would result in a wellhead pressure of 3100 kPa. These predictions assume a constant linear pressure buildup (an homogeneous, isotropic aquifer).

The dependence of buildup curves on the temperature of the injection water results in uncertainties in predicting injection well performance during power plant operation. An injection test utilizing water of the temperature of power plant effluent should be conducted to evaluate these predictions. A testing program using rates and times identical to the August 1979 test would be preferrable. Direct comparison of test results could then be made.

CONCLUSIONS AND RECOMMENDATIONS

1. No aquifer boundaries were recognized in the RRGI-7 data.

2. The data is thermally affected, therefore, RRGI-7 should be injection tested with water near the temperature of plant effluent. This test will help to predict well performance during actual plant operation.

3. Stimulation of RRGI-7 should not be attempted, without additional testing of RRGI-7.

4. The well efficiency of RRGI-7 is dependent on the temperature of the injection water.

5. Wellhead temperature measurements must be recorded during recovery to assist in the analysis of recovery data.

6. RRGI-7 could inject at the pumps maximum capacity 69.4 lps for the 21-day RRGE-1 test.

7. RRGI-7 and RRGI-6 do not have the capacity to continually inject 1577 lps for 5 years and maintain wellhead pressures below 3450 kPa.

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TABLE 1. RRGI-7 WELL TEST DATA
August 1979

Q lps	Date	Time	t (min)	Initial WHP kPa	Shut-in WHP °C	Initial WHT kPa	Shut-in WHT kPa	Initial D.H.P[a] °C	Shut-in D.H.P.[a] kPa	Initial D.H.T. °C	Final D.H.T. °C
47.3	8/9/79	09:22:40 to 10:14:00	51	441.3	1220.4	103.1	114.7				
Recovery			198								
47.3	8/9/79	13:32:20 to 19:09:20	337	446.1	1337.6	106.7	131.4	11499.6	12292.0	97.2	122.4
Recovery			994								
39.1	8/10/79	11:43:00 to 19:43:00	480	401.3	1213.5	99.7	130.8	11546.0	12168.3	110.3	122.1
Recovery			805								
28.4	8/11/79	09:07:50 to 09:13:00	5765	450.9	1041.1	84.4	122.8	11601.1		112.2	112.2
Recovery											

[a]Probe at a depth of 999.74 m. (3280 ft.) below land surface.

[b]Data questionable.

TABLE 2. RRGI-7 INJECTION RATES
August 1979

Q	RANGE	% VARIATION
47.3 lps #1	44.4 - 49.2 lps	10
47.3 lps #2	46.5 - 48.2 lps	3.5
28.4 lps	27.5 - 29.2 lps	5.9

where: Q = injection rate
Range = low and high injection rate

TABLE 3. RRGI-7 RECEIVING ZONES
(August 1979 Injection Test)

DEPTH (m)	VOLUME lps	% FLOW	LITHOLOGY
730 - 790	6.9	24	Bedded sandstones and siltstones.
804 - 829	4.7	17	Bedded sandstones and siltstones with possible solution openings.
844 - 905	8.21	29	Bedded sandstones and siltstones.
961 - 1000	3.8	13	Sandstone exhibiting variations in depth.
1000 - 1186	4.7	17	Sandstone and siltstone.

TABLE 4. TIME OF CESSATION OF RECOVERY LINEAR TREND

TEST lps	METHOD OF MEASUREMENT	t/t^1	t^1 (min)	CALCULATED RECOVERY (min)	TEMPERATURE °C
47.3	WHP	6	70	50	131
	HP	11	33	16	122
39.1	WHP	20	25	25	131
	HP	27	20	--[a]	122
28.4	WHP	65	90	42	128
	HP	6.4	1127	--[b]	122

[a]No calculated recovery due to poor definition of buildup trend.
[b]No calculated recovery due to HP malfunction.

TABLE 5. RRGI-7 WELL LOSSES OCCURING AT 300 MINUTES

Q lps	s kPa	Cal. Rec. kPa	Theis kPa	C kPa
47.3	910	410 45%	210 23%	830 91%
39.1	807	340 43%	620 51%	---
28.4	517	410 80%	100 20%	480 93%

Cal. Rec. = well losses estimated by comparing buildup and calculated recovery data.
Theis = well losses estimated by comparing actual drawdown with drawdown predicted by the non-equilibrium equation.
C = well losses estimated from well losses.
% = percent of buildup caused by well losses.

TABLE 6. OBSERVATION WELLS USED DURING THE TESTING OF RRGI-7

WELL	r m	DIRECTION	DEPTH m	OPEN HOLE m
RRGI-7			1176	623
RRGI-6	792	NE	1176	623
RRGE-3	792	NW	1803	1291
MW-3	1024	NW	152	perf. 140-152
MW-4	911	N	305	254 perf. 241-254
MW-5	1097	NE	152	136 perf. 124-136
MW-6	1167	NE	313	283
MW-7	597	NE	152	perf. 40-152

TABLE 7. RRGI-7 AUGUST 1979 INJECTION TEST RESULTS

TEST	lps	TIME	s_{10} kPa/log cycle	Q/s_{10} lps/kPa/log cycle
Aug. 9 #1 Injection WHP	47.3	1-23	150	0.3147
Aug. 9 #2 Injection WHP	47.3	1-20	170	0.2789
Aug. 9 #2 Injection WHP	47.3	170-340	27.6	1.715
Aug. 10 Injection WHP	39.1	1-20	131	0.2985
Aug. 10 Injection WHP	39.1	200-480	75.8	0.5155
Aug. 11-15 Injection WHP	28.4	1-20	48.3	0.5884
Aug. 9 #1 Injection HP	47.3			
Aug. 9 #2 Injection HP	47.3			
Aug. 10 Injection HP	39.1	1-450		
Aug. 11-15 Injection HP	28.4	0.5-2850	48.3	0.5884
Aug. 9 Recovery WHP	47.3	0.33-40	131	0.3611
Aug. 10 Recovery WHP	39.1	0.33-30	110	0.3544
Aug. 15 Recovery WHP	28.4	2-90	86.2	0.3295

TABLE 7. (CONTINUED)

TEST	lps	TIME	s_{10} kPa/log cycle	Q/s_{10} lps/kPa/log cycle
Aug. 15 Recovery WHP(Heise)	28.4	197-1127	221	0.1287
Aug.9-10 Recovery	47.3			
Aug.10-11 Recovery HP	39.1	4.5-19	176	0.2224
Aug. 15 Recovery HP	28.4			
Aug.9-10 Calculated Recovery WHP	47.3	1-60	128	0.3708
Aug. 9-10 Calculated Recovery HP	47.3	1-16	152	0.3118
Aug. 10-11 Calculated Recovery WHP	39.1	1-38	113	0.3458
Aug. 15 Calculated Recovery WHP	28.4	1-43	87.6	0.3243

NOTE: The Hewlett Packard Downhole Probe was installed at 1132 m.

TABLE 8. RRGI-7 PRESSURE PREDICTIONS BASED UPON AUGUST 1979 INJECTION TEST

	Test	Q lps	Data Used	Extrapolated 8 hours kPa	Wellhead Pressure 21 days kPa
(1)	Aug. 9 WHP	47.3	0-185 minutes	1440	1790

(a) The ratio technique indicates that the injection of 75.7 lps for 8 hours will result in a wellhead pressure of 2300 kPa.

(b) The ratio technique indicates that the injection of 82.0 lps for 21 days will result in a wellhead pressure of 3100 kPa.

	Test	Q lps	Data Used	Extrapolated 8 hours kPa	Wellhead Pressure 21 days kPa
(2)	Aug. 9 WHP	47.3	185-300 minutes	1360	1420

(a) The ratio technique indicates that the injection of 75.7 lps for 8 hours will result in a wellhead pressure of 220 kPa.

(b) The ratio technique indicates that the injection of 100 lps for 21 days will result in a wellhead pressure of 3100 kPa.

	Test	Q lps	Data Used	Extrapolated 8 hours kPa	Wellhead Pressure 21 days kPa
(3)	Aug. 10 WHP	39.1	200-480 minutes	1210	1350

(a) The ratio technique indicates that the injection of 75.7 lps for 8 hours will result in a wellhead pressure of 2350 kPa.

(b) The ratio technique indicates that the injection of 88.3 lps for 21 days will result in a wellhead pressure of 3100 kPa.

TABLE 8. (CONTINUED)

(4) Test	Q lps	Data Used	Extrapolated 8 hours kPa	Wellhead Pressure 21 days kPa
Aug.1-15 WHP	28.4	300-4750 minutes	980	1090

(a) The ratio technique indicates that the injection of 75.7 lps for 8 hours will result in a wellhead pressure of 2600 kPa.

(b) The ratio technique indicates that the injection of 80.7 lps for 21 days will result in a wellhead pressure of 3100 kPa.

(5) Test	Q lps	Data Used	Extrapolated 8 hours kPa	Wellhead Pressure 21 days kPa
Aug.11-15 HP Data	28.4	2-2800 minutes	119	120

(a) The ratio technique indicates that the injection of 75.7 lps for 8 hours will result in a borehole pressure of 31.8 MPa at a depth of 1132 m.

(b) The ratio technique indicates that the injection of 75.7 lps for 21 days will result in a borehole pressure of 32.1 MPa at a depth of 1132 m.

Assumptions:

A. Q/s_{10} is not dependent on Q.

B. No aquifer boundaries.

C. No well interference.

D. No change in temperature of injection or aquifer water.

E. A constant injection rate is maintained.

TABLE 8. (CONTINUED)

Test	Q lps	Q/s_{10} lps/kPa/log cycle	Extrapolated 8 hours kPa	Wellhead Pressure kPa	Water Temperature ^{o}C
Aug. 1978	53.0	0.03			
Nov. 1978	25.2	0.0347	880	2280	$14\text{-}4^{o}$

(a) The ratio technique indicated that the injection of 75.7 lps for 8 hours will result in a wellhead pressure of 2650 kPa.

(b) The ratio technique indicated that the injection of 34.1 lps for 21 days will result in a wellhead pressure of 3100 kPa.

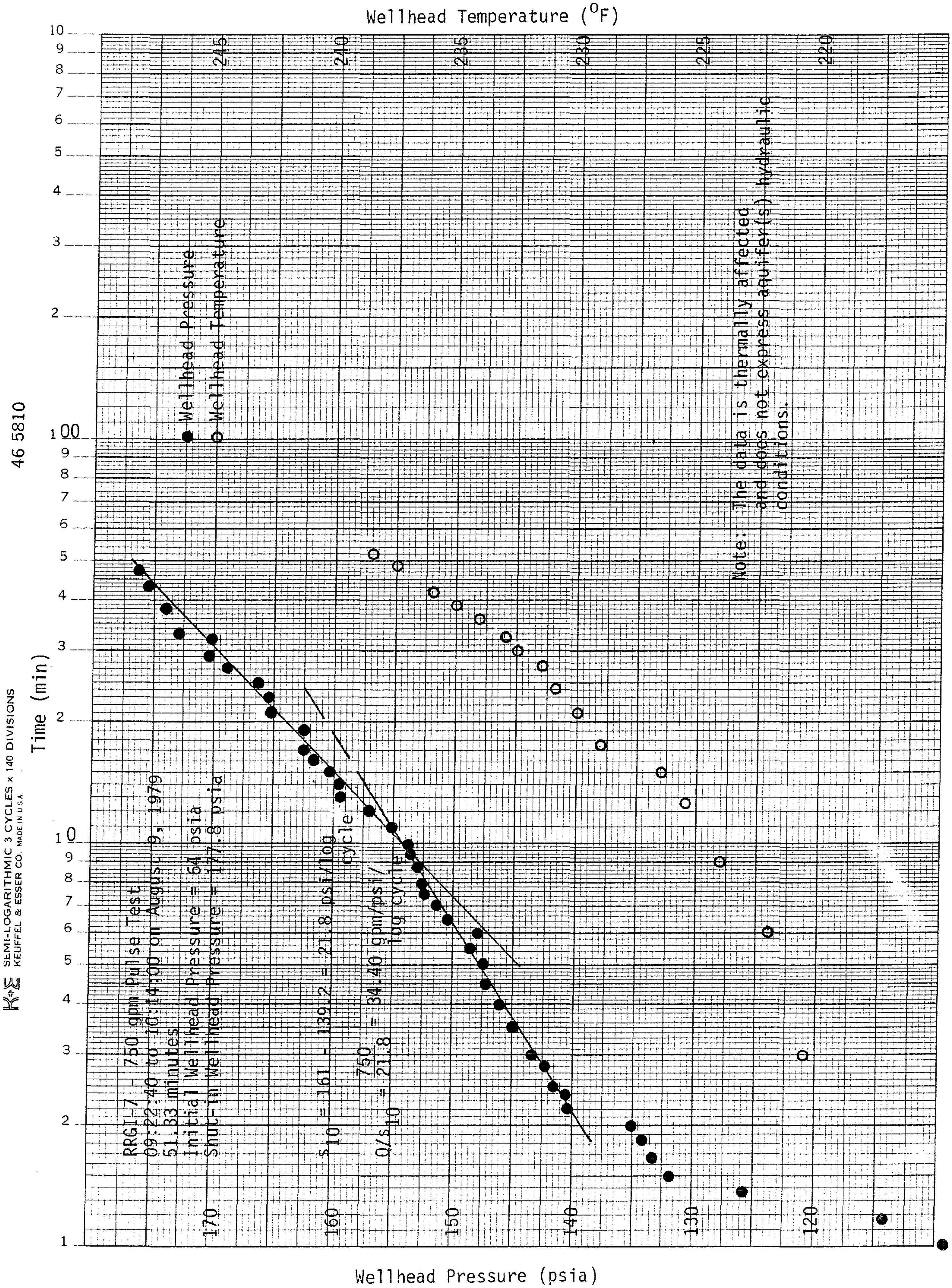

Wellhead Temperature (^{O}F)
245
240
235
230
225
220
Wellhead Pressure
Wellhead Temperature
Note: The data is thermally affected and does not express aquifer(s) hydraulic conditions.
RRGI-7 - 750 gpm Pulse Test
09:22:40 to 10:14:00 on August 9, 1979
51.33 minutes
Initial Wellhead Pressure = 64 psia
Shut-in Wellhead Pressure = 177.8 psia
s_{10} = 161 - 139.2 = 21.8 psi/log cycle
Q/s_{10} = $\frac{750}{21.8}$ = 34.40 gpm/psi/log cycle
Time (min)
170
160
150
140
130
120
Wellhead Pressure (psia)
46 5810
SEMI-LOGARITHMIC 3 CYCLES x 140 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

FIGURE 1

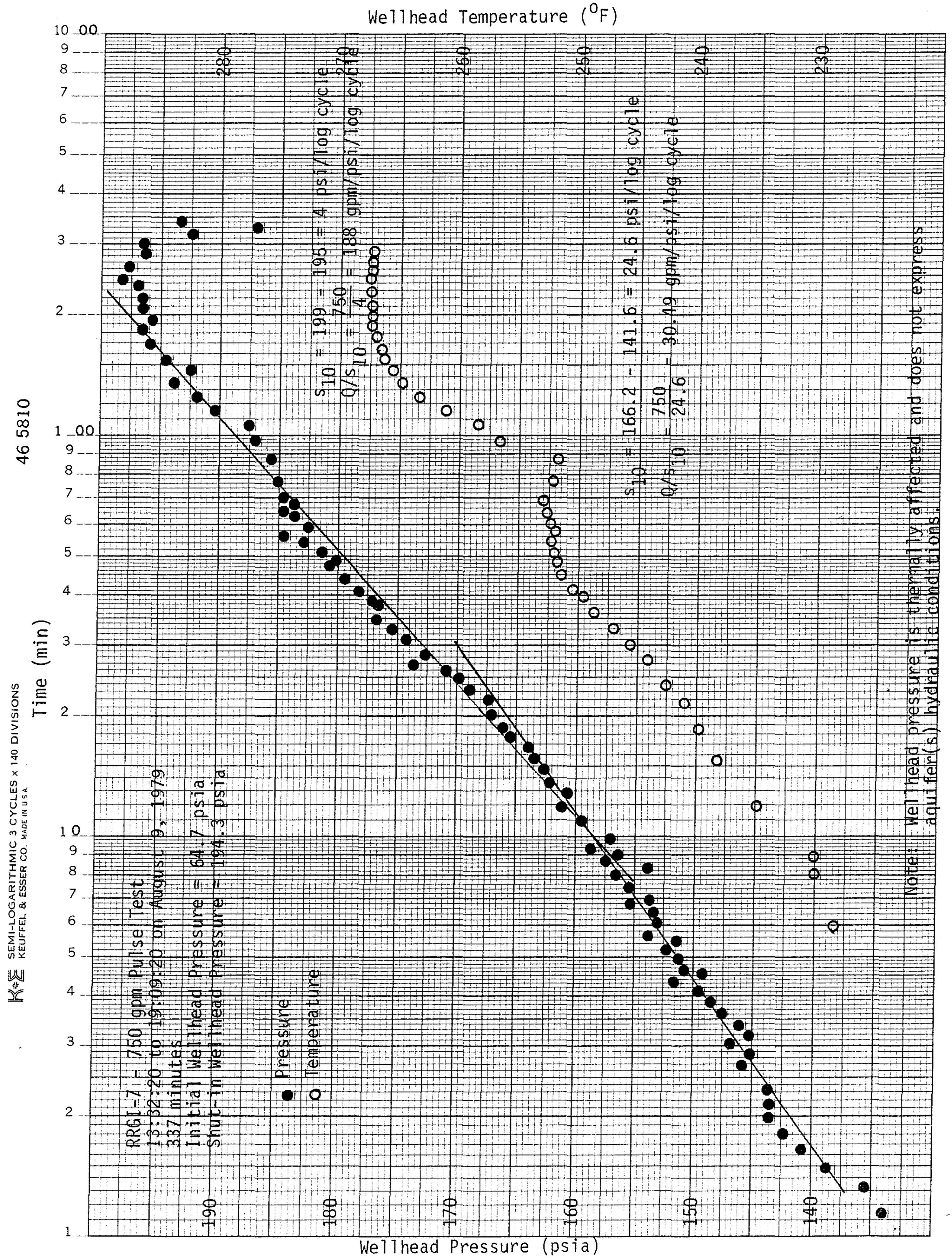
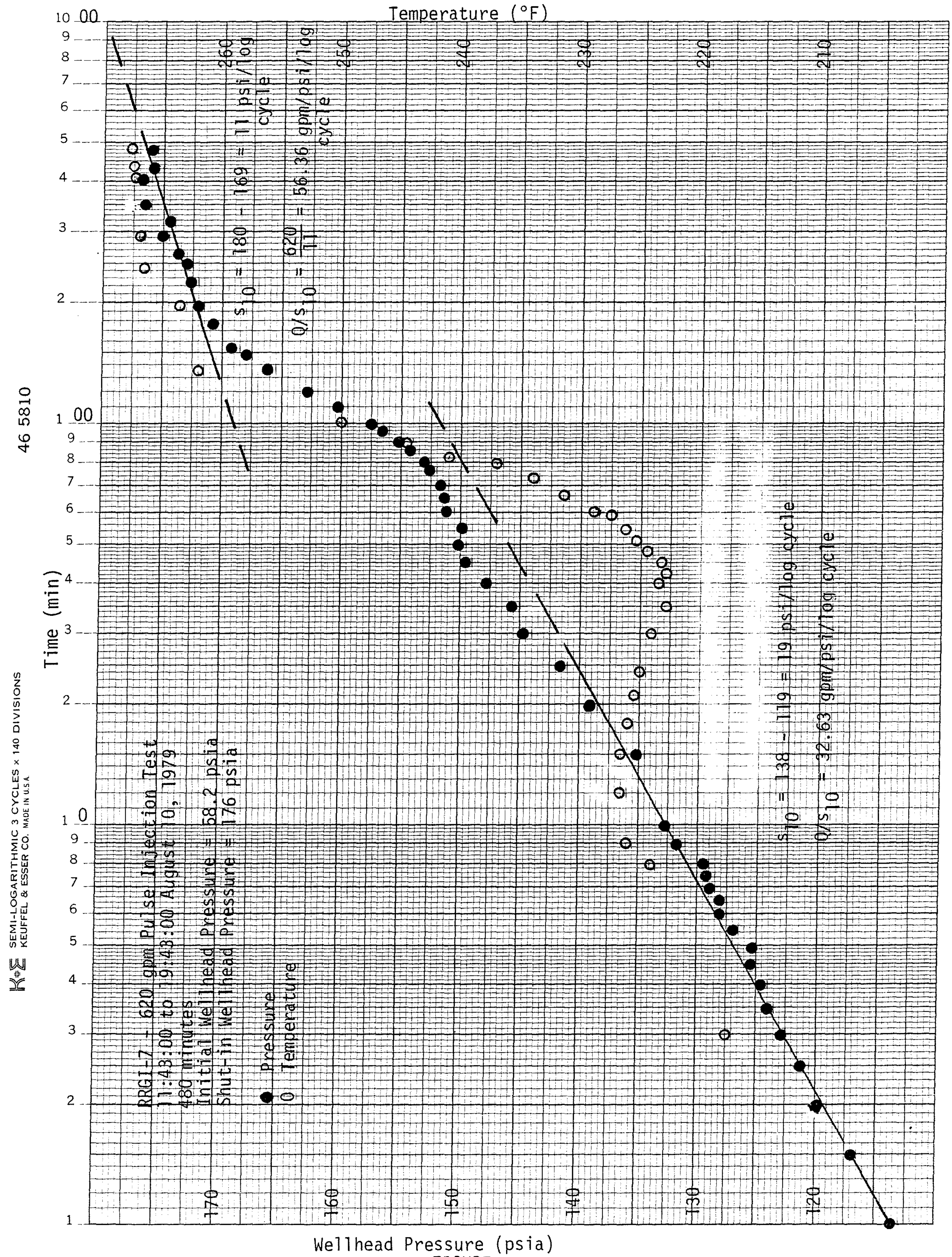

Wellhead Temperature (°F)
280
270
260
250
240
230
s10 = 199 - 195 = 4 psi/log cycle
Q/s10 = 750/4 = 188 gpm/psi/log cycle
s10 = 166.2 - 141.6 = 24.6 psi/log cycle
Q/s10 = 750/24.6 = 30.49 gpm/psi/log cycle
Note: Wellhead pressure is thermally affected and does not express aquifer(s) hydraulic conditions.
46 5810
Time (min)
SEMI-LOGARITHMIC 3 CYCLES x 140 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
RRGI-7 - 750 gpm Pulse Test
13:32:20 to 19:09:20 on August 9, 1979
337 minutes
Initial Wellhead Pressure = 64.7 psia
Shut-in Wellhead Pressure = 194.3 psia
Pressure
Temperature
190
180
170
160
150
140
Wellhead Pressure (psia)

FIGURE 2



Temperature (°F)
Time (min)
Wellhead Pressure (psia)
RRGI-7 - 620 gpm Pulse Injection Test
11:43:00 to 19:43:00 August 10, 1979
480 minutes
Initial Wellhead Pressure = 58.2 psia
Shut-in Wellhead Pressure = 176 psia
Pressure
Temperature
s10 = 180 - 169 = 11 psi/log cycle
Q/s10 = 620/11 = 56.36 gpm/psi/log cycle
s10 = 138 - 119 = 19 psi/log cycle
Q/s10 = 32.63 gpm/psi/log cycle
46 5810
SEMI-LOGARITHMIC 3 CYCLES x 140 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

FIGURE 3

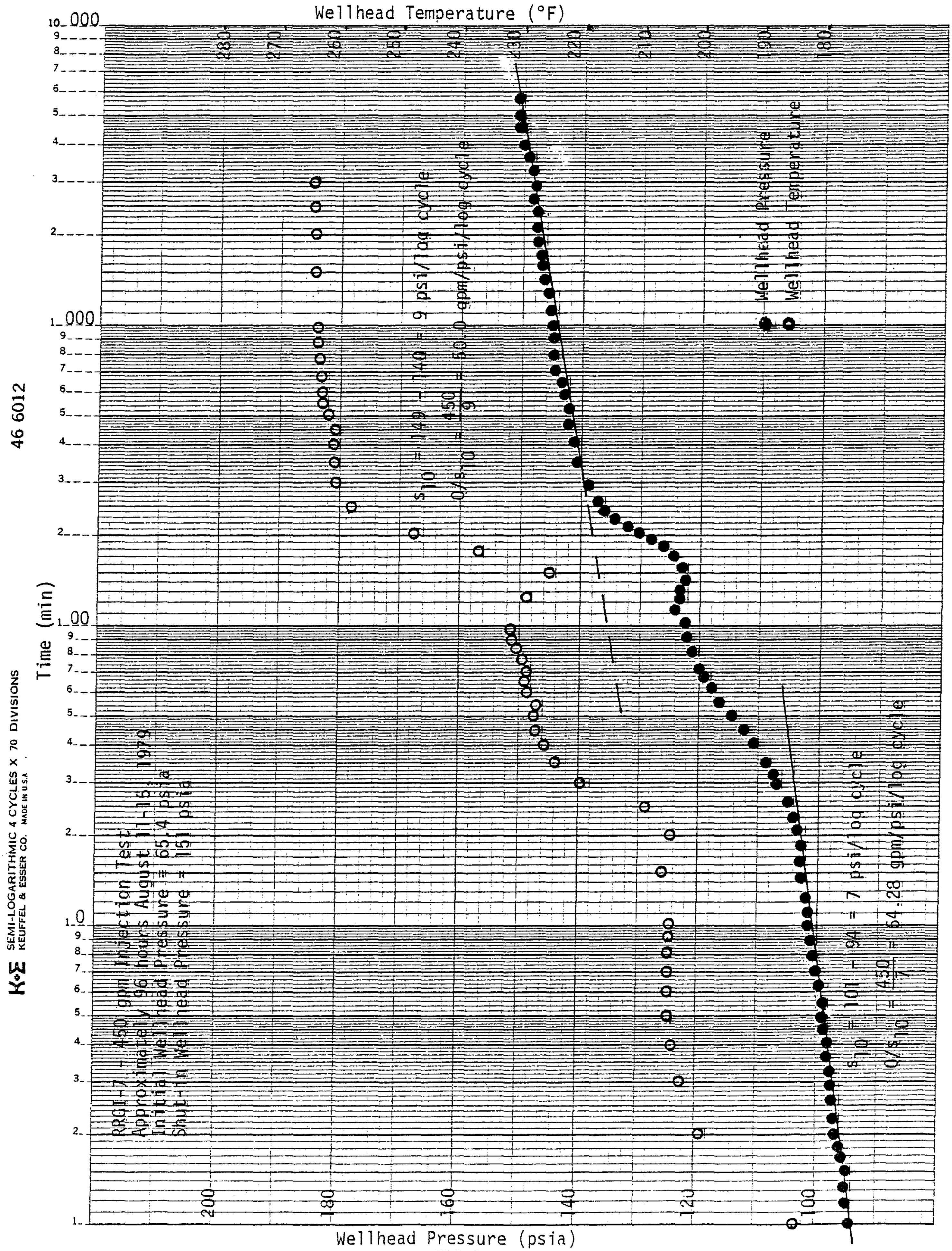
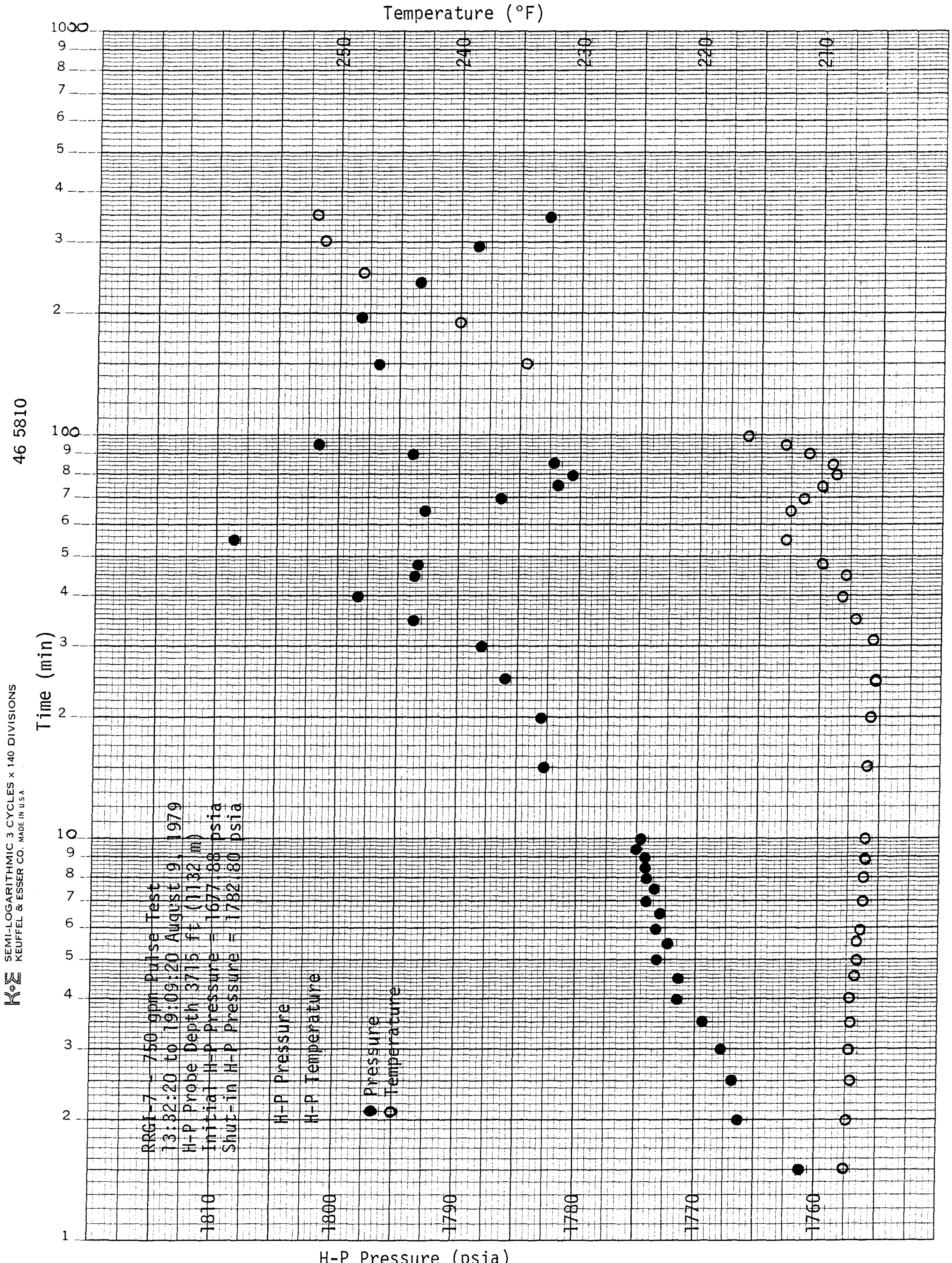

Wellhead Temperature (°F)
280
270
260
250
240
230
220
210
200
190
180
Wellhead Pressure
Wellhead Temperature
s10 = 149 - 140 = 9 psi/log cycle
Q/s10 = 450/9 = 50.0 gpm/psi/log cycle
46 6012
Time (min)
K+E SEMI-LOGARITHMIC 4 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
RRGI-7 - 450 gpm Injection Test
Approximately 96 hours August 11-15, 1979
Initial Wellhead Pressure = 65.4 psia
Shut-in Wellhead Pressure = 151 psia
s10 = 101 - 94 = 7 psi/log cycle
Q/s10 = 450/7 = 64.28 gpm/psi/log cycle
200
180
160
140
120
100
Wellhead Pressure (psia)

FIGURE 4


Temperature (°F)
250
240
230
220
210
Time (min)
1000
100
10
1
H-P Pressure (psia)
1810
1800
1790
1780
1770
1760
RRGI-7 - 750 gpm Pulse Test
13:32:20 to 19:09:20 August 9, 1979
H-P Probe Depth 3715 ft (1132 m)
Initial H-P Pressure = 1677.88 psia
Shut-in H-P Pressure = 1782.80 psia
H-P Pressure
H-P Temperature
● Pressure
o Temperature
46 5810
SEMI-LOGARITHMIC 3 CYCLES x 140 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
FIGURE 5

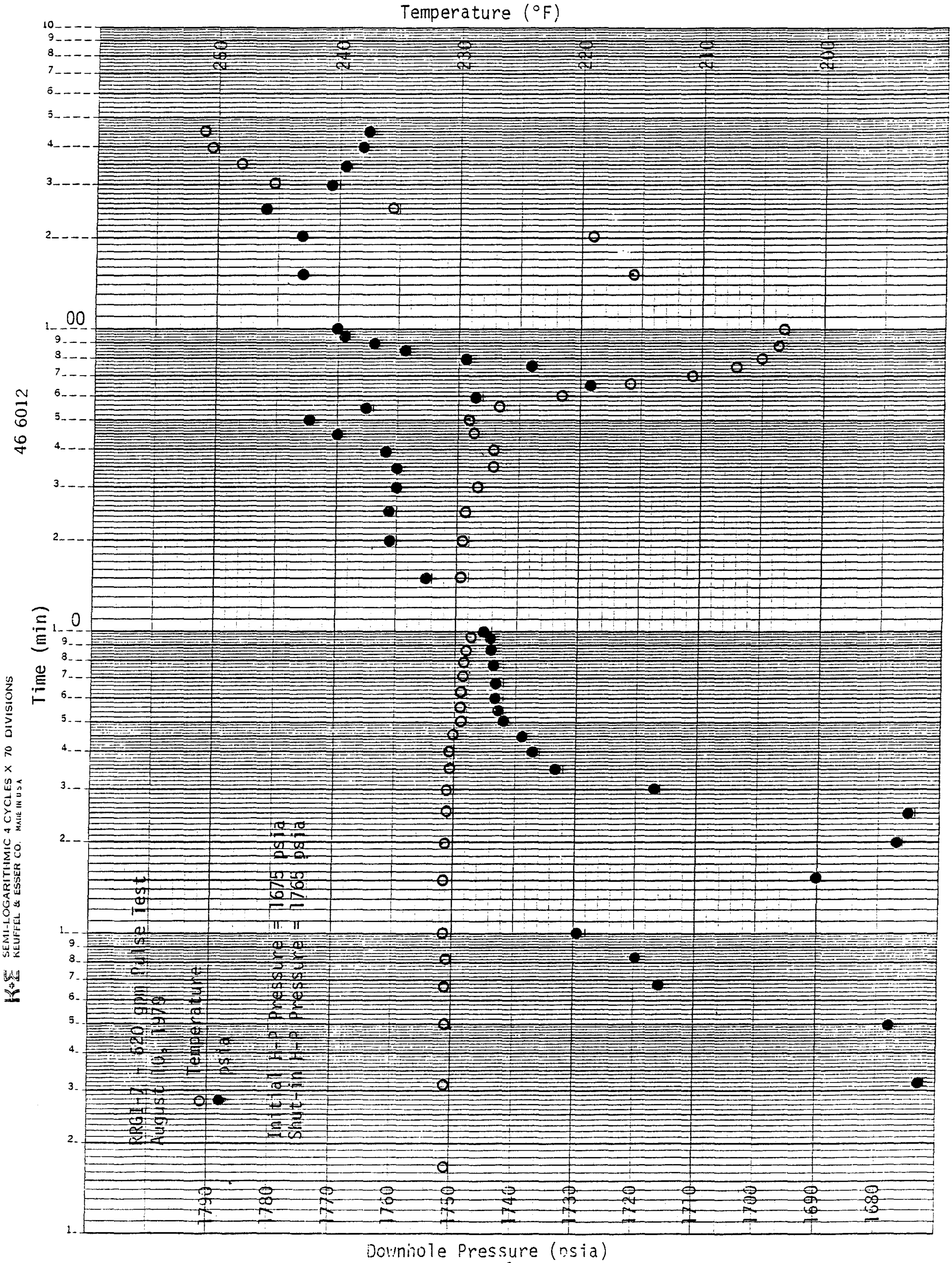

Temperature (°F)
260
240
230
220
210
200
Time (min)
RRGI-7 - 620 gpm Pulse Test
August 10, 1979
Temperature
psia
Initial H-P Pressure = 1675 psia
Shut-in H-P Pressure = 1765 psia
1790
1780
1770
1760
1750
1740
1730
1720
1710
1700
1690
1680
Downhole Pressure (psia)
46 6012
K+E SEMI-LOGARITHMIC 4 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

FIGURE 6

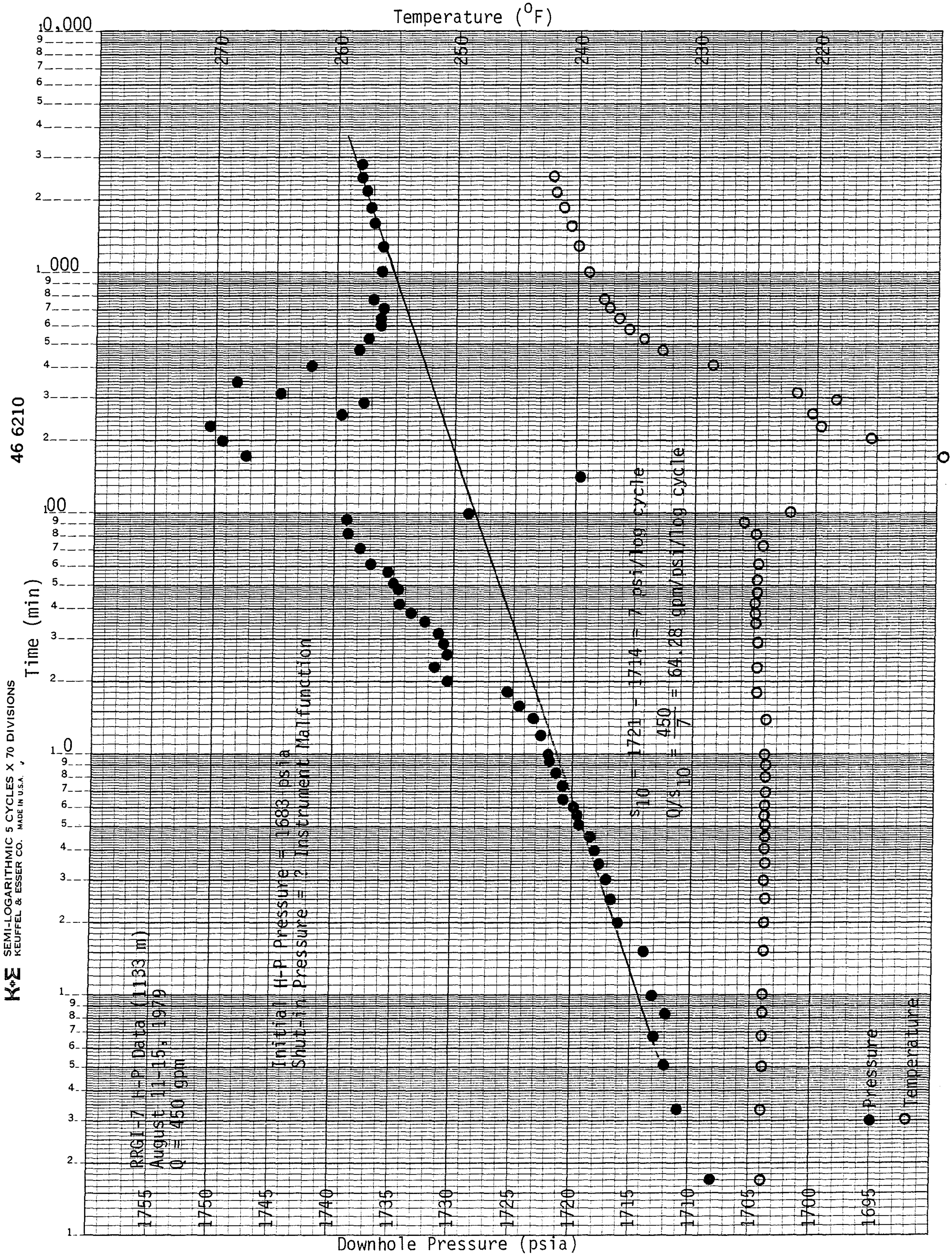
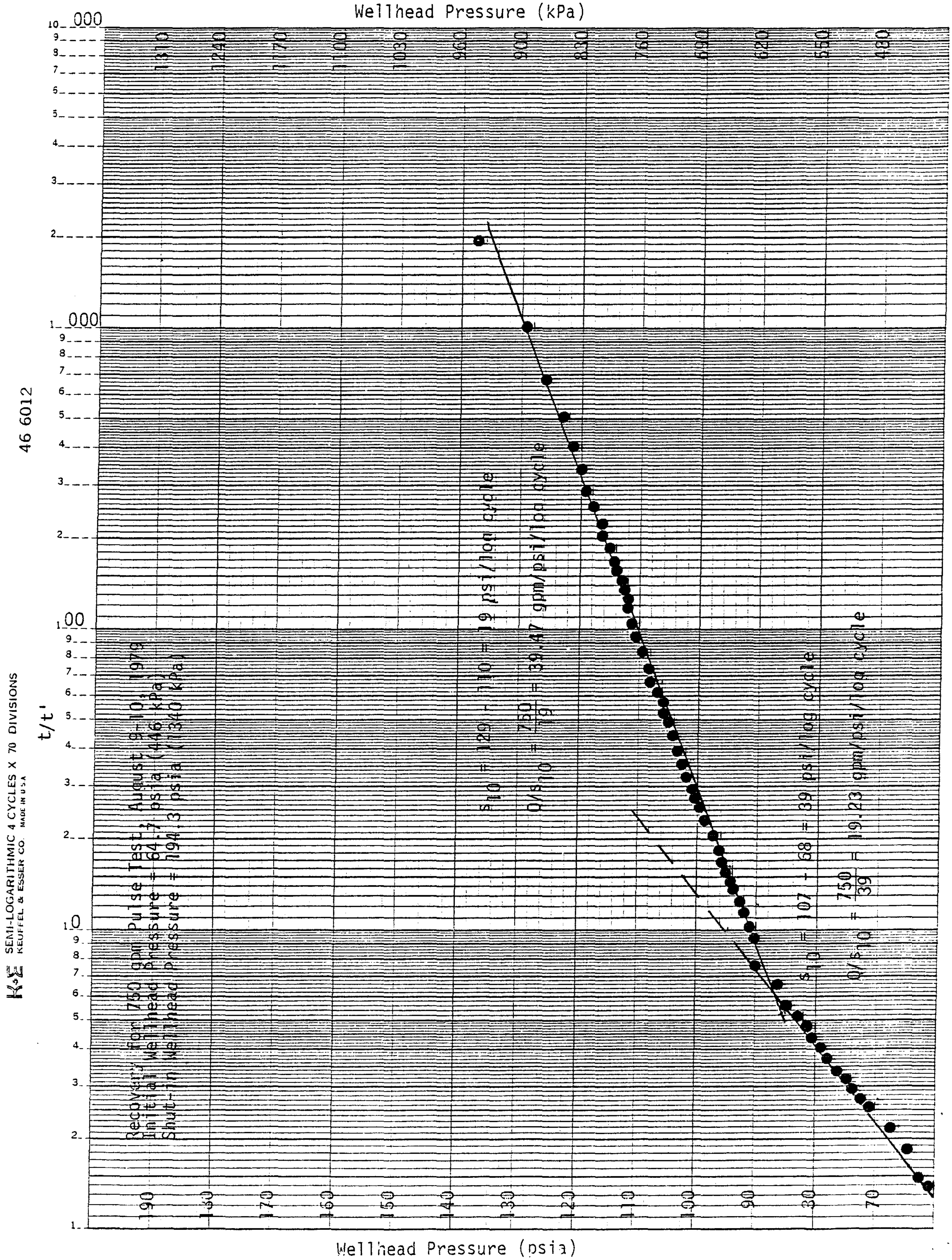
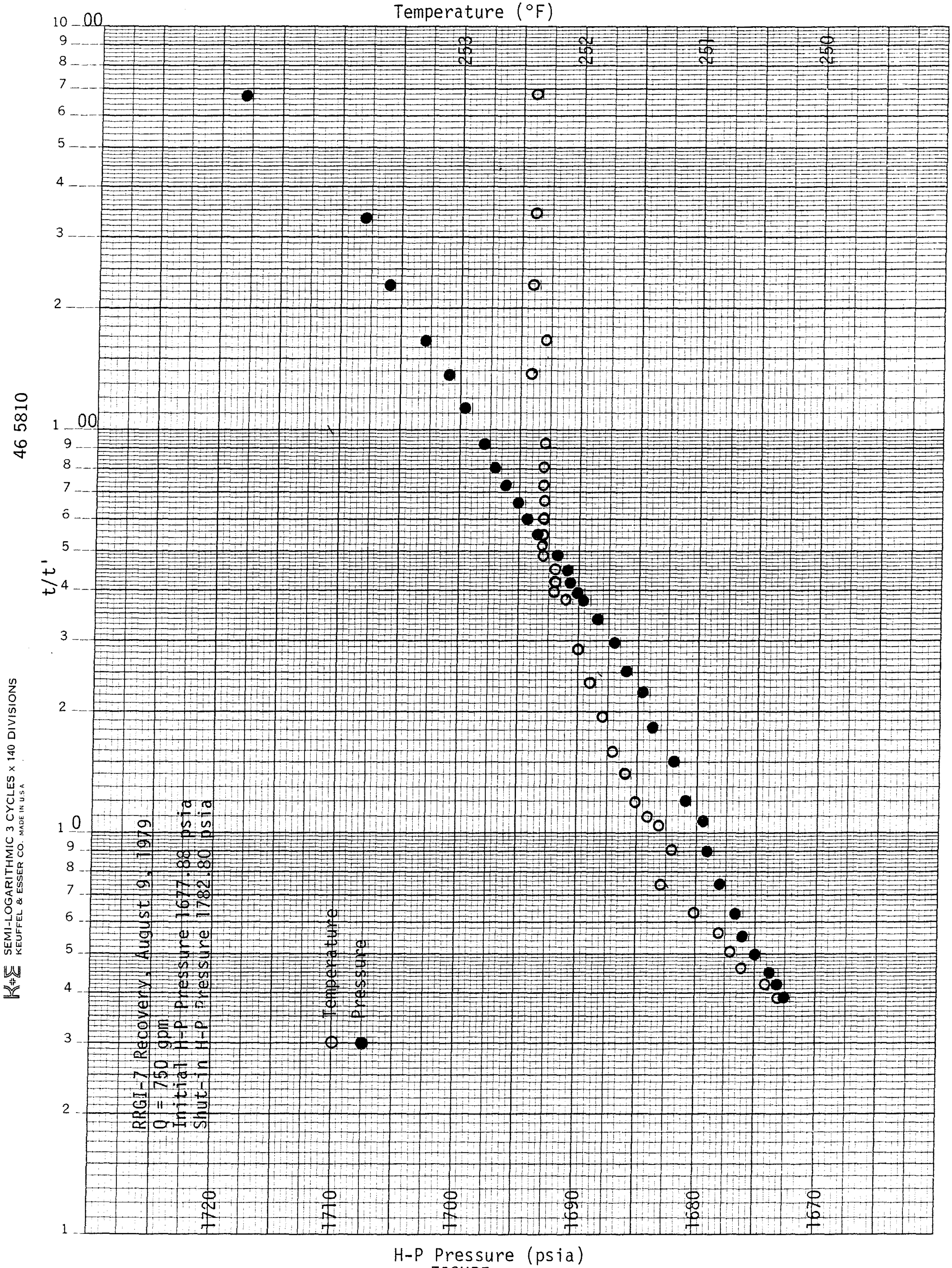

Temperature (°F)
Time (min)
Downhole Pressure (psia)
RRGI-7 H-P Data (1133 m)
August 11-15, 1979
Q = 450 gpm
Initial H-P Pressure = 1683 psia
Shut-in Pressure = ? Instrument Malfunction
s_{10} = 1721 - 1714 = 7 psi/log cycle
$Q/s_{10} = \frac{450}{7}$ = 64.28 gpm/psi/log cycle
Pressure
Temperature
46 6210
SEMI-LOGARITHMIC 5 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

FIGURE 7



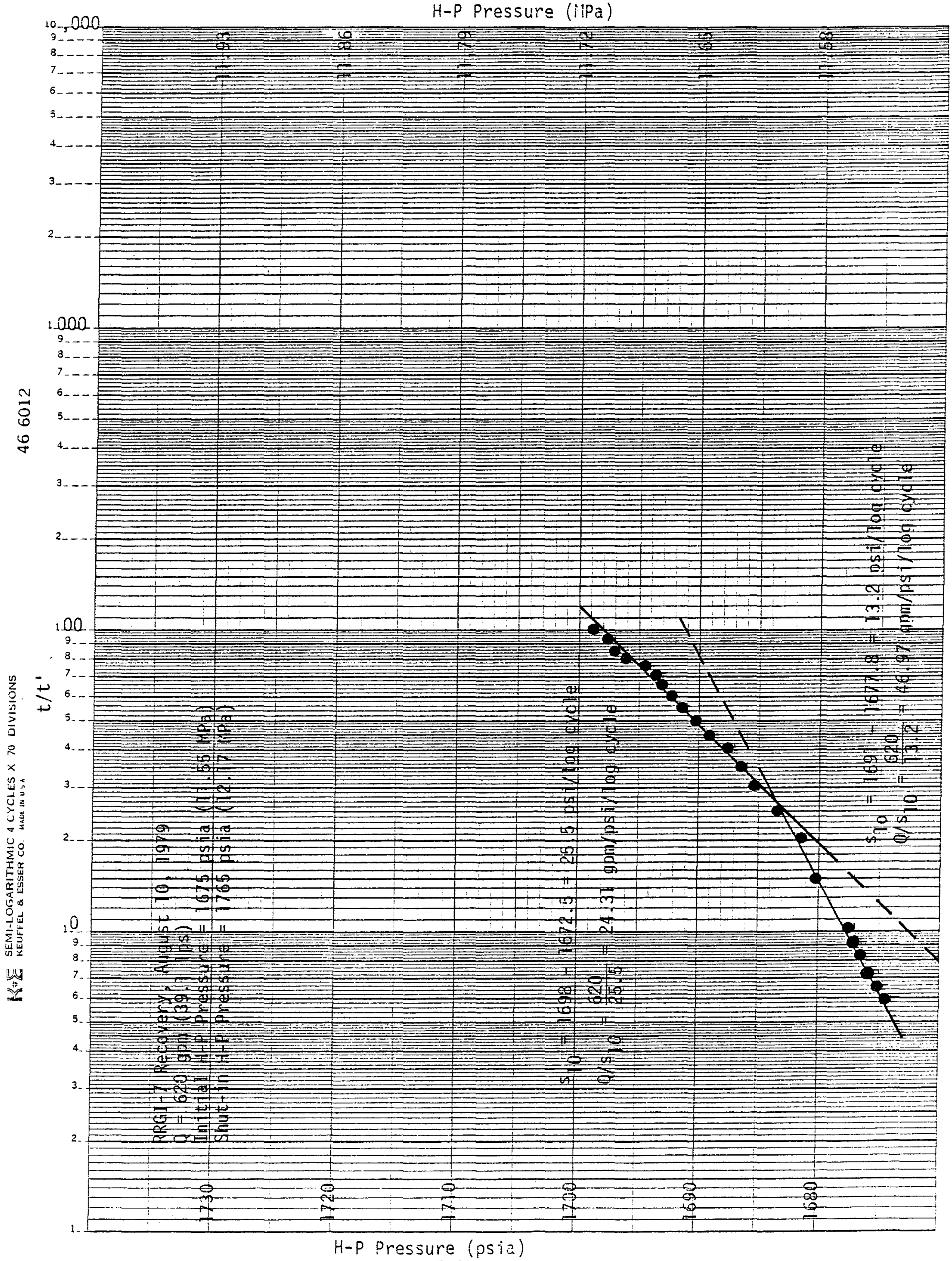
Wellhead Pressure (kPa)
Wellhead Pressure (psia)
t/t'
Recovery for 750 gpm Pulse Test, August 9-10, 1979
Initial Wellhead Pressure = 64.7 psia (446 kPa)
Shut-in Wellhead Pressure = 194.3 psia (1340 kPa)
s10 = 129 - 110 = 19 psi/log cycle
Q/s10 = 750/19 = 39.47 gpm/psi/log cycle
s10 = 107 - 68 = 39 psi/log cycle
Q/s10 = 750/39 = 19.23 gpm/psi/log cycle
SEMI-LOGARITHMIC 4 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 6012

FIGURE 8



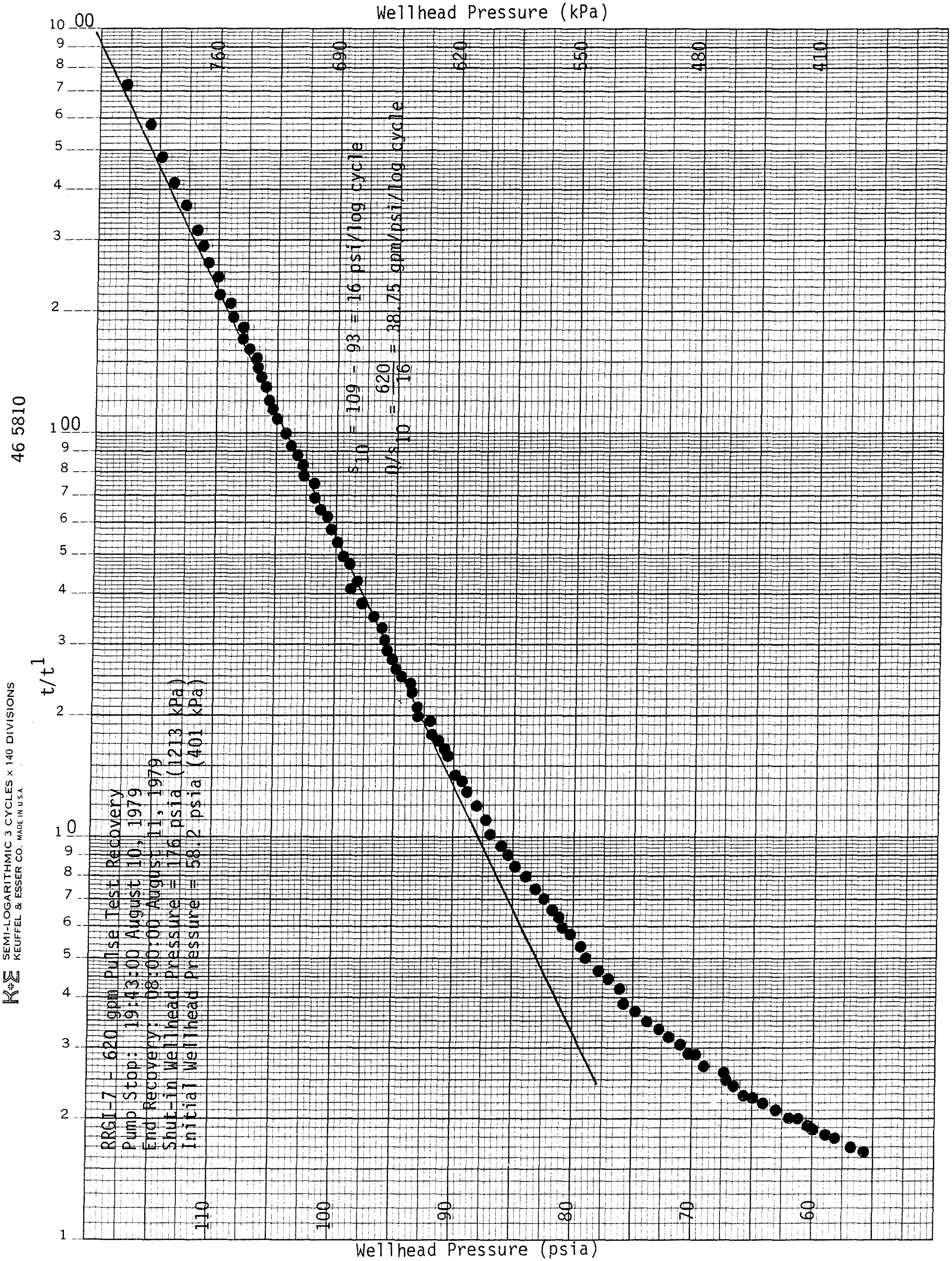
Temperature (°F)
253
252
251
250
t/t'
H-P Pressure (psia)
1720
1710
1700
1690
1680
1670
RRGI-7 Recovery, August 9, 1979
Q = 750 gpm
Initial H-P Pressure 1677.88 psia
Shut-in H-P Pressure 1782.80 psia
Temperature
Pressure
46 5810
SEMI-LOGARITHMIC 3 CYCLES x 140 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

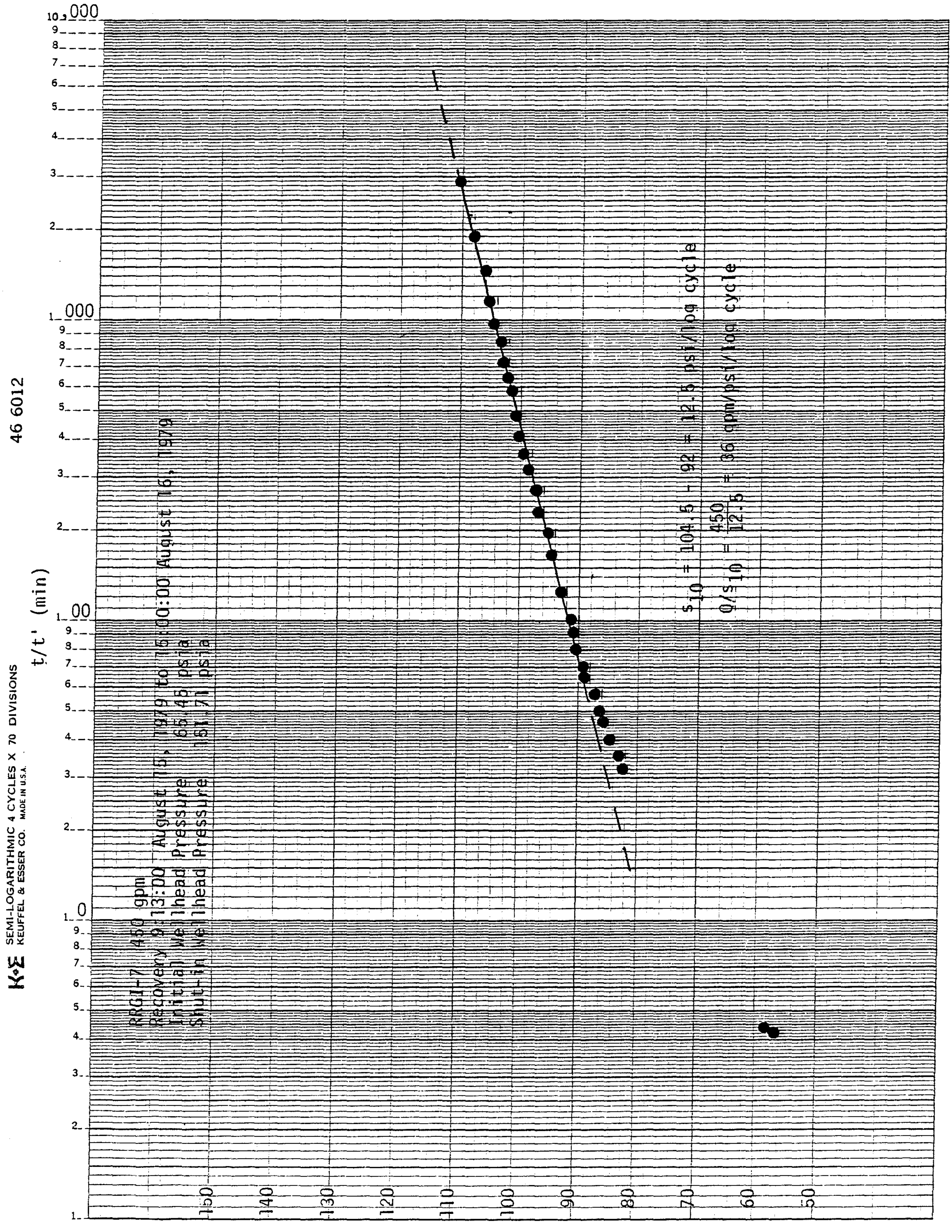
FIGURE 9



H-P Pressure (MPa)
11.93
11.86
11.79
11.72
11.65
11.58
10,000
1,000
100
10
1
t/t'
46 6012
SEMI-LOGARITHMIC 4 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
RRGI-7 Recovery, August 10, 1979
Q = 620 gpm (39.1 lps)
Initial H-P Pressure = 1675 psia (11.55 MPa)
Shut-in H-P Pressure = 1765 psia (12.17 MPa)
s_{10} = 1698 - 1672.5 = 25.5 psi/log cycle
$Q/s_{10} = \frac{620}{25.5}$ = 24.31 gpm/psi/log cycle
s_{10} = 1691 - 1677.8 = 13.2 psi/log cycle
$Q/s_{10} = \frac{620}{13.2}$ = 46.97 gpm/psi/log cycle
1730
1720
1710
1700
1690
1680
H-P Pressure (psia)

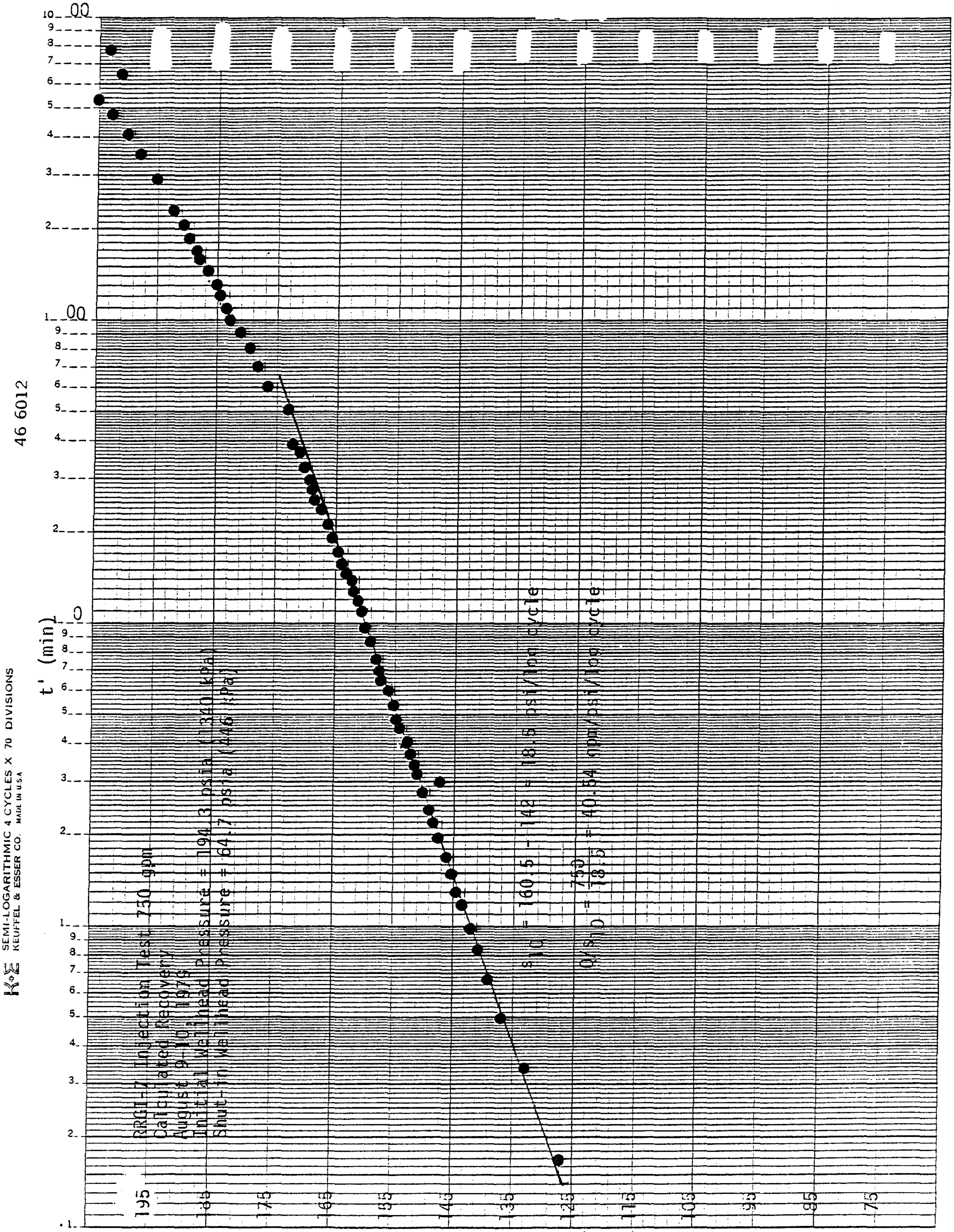
FIGURE 10


Wellhead Pressure (kPa)
760
690
620
550
480
410
s_{10} = 109 - 93 = 16 psi/log cycle
$Q/s_{10} = \frac{620}{16}$ = 38.75 gpm/psi/log cycle
46 5810
t/t1
K+E SEMI-LOGARITHMIC 3 CYCLES × 140 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
RRGI-7 - 620 gpm Pulse Test Recovery
Pump Stop: 19:43:00 August 10, 1979
End Recovery: 08:00:00 August 11, 1979
Shut-in Wellhead Pressure = 176 psia (1213 kPa)
Initial Wellhead Pressure = 58.2 psia (401 kPa)
110
100
90
80
70
60
Wellhead Pressure (psia)
FIGURE 11



Wellhead Pressure (psia)

FIGURE 12



Calculated Recovery (psia)
FIGURE 13

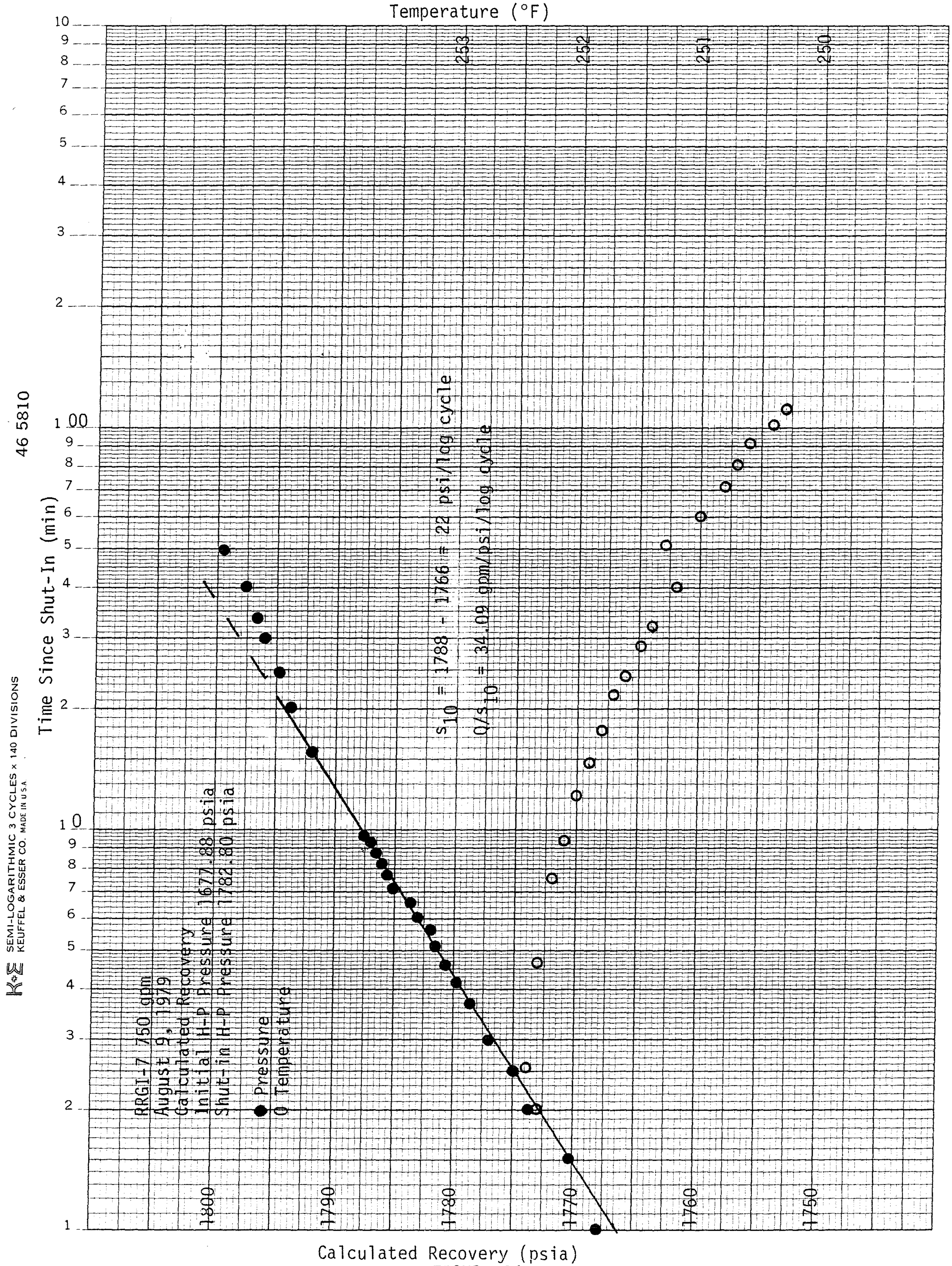

Temperature (°F)
253
252
251
250
Time Since Shut-In (min)
100
10
1
S_{10} = 1788 - 1766 = 22 psi/log cycle
Q/S_{10} = 34.09 gpm/psi/log cycle
RRGI-7 750 gpm
August 9, 1979
Calculated Recovery
Initial H-P Pressure 1677.88 psia
Shut-in H-P Pressure 1782.80 psia
● Pressure
O Temperature
1800
1790
1780
1770
1760
1750
Calculated Recovery (psia)
46 5810
K&E SEMI-LOGARITHMIC 3 CYCLES × 140 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

FIGURE 14

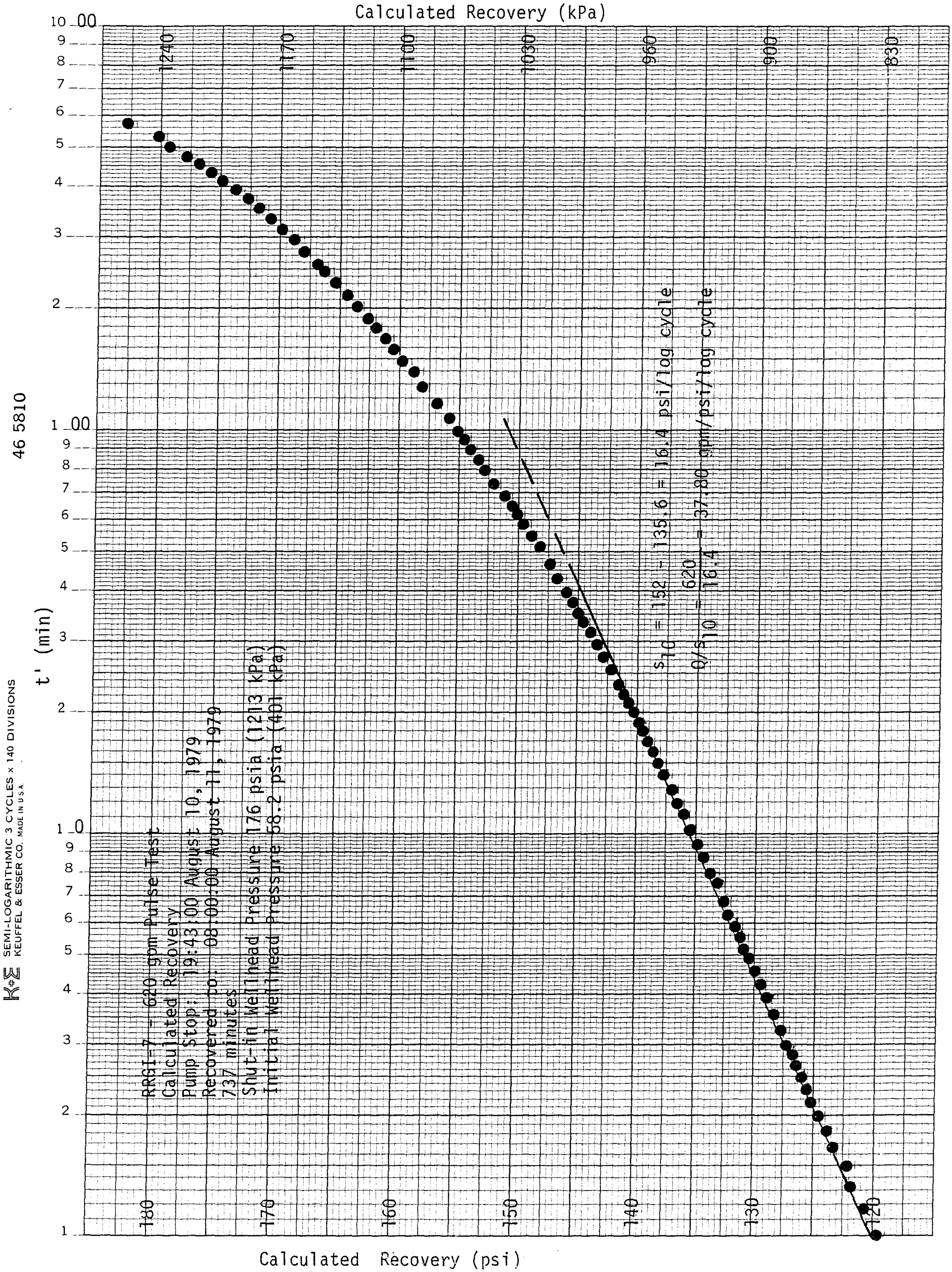

Calculated Recovery (kPa)
1240
1170
1100
1030
960
900
830
t' (min)
RRGI-7 - 620 gpm Pulse Test
Calculated Recovery
Pump Stop: 19:43:00 August 10, 1979
Recovered to: 08:00:00 August 11, 1979
737 minutes
Shut-in Wellhead Pressure 176 psia (1213 kPa)
Initial Wellhead Pressure 58.2 psia (401 kPa)
s10 = 152 - 135.6 = 16.4 psi/log cycle
Q/s10 = 620/16.4 = 37.80 gpm/psi/log cycle
180
170
160
150
140
130
120
Calculated Recovery (psi)
46 5810
SEMI-LOGARITHMIC 3 CYCLES x 140 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

FIGURE 15

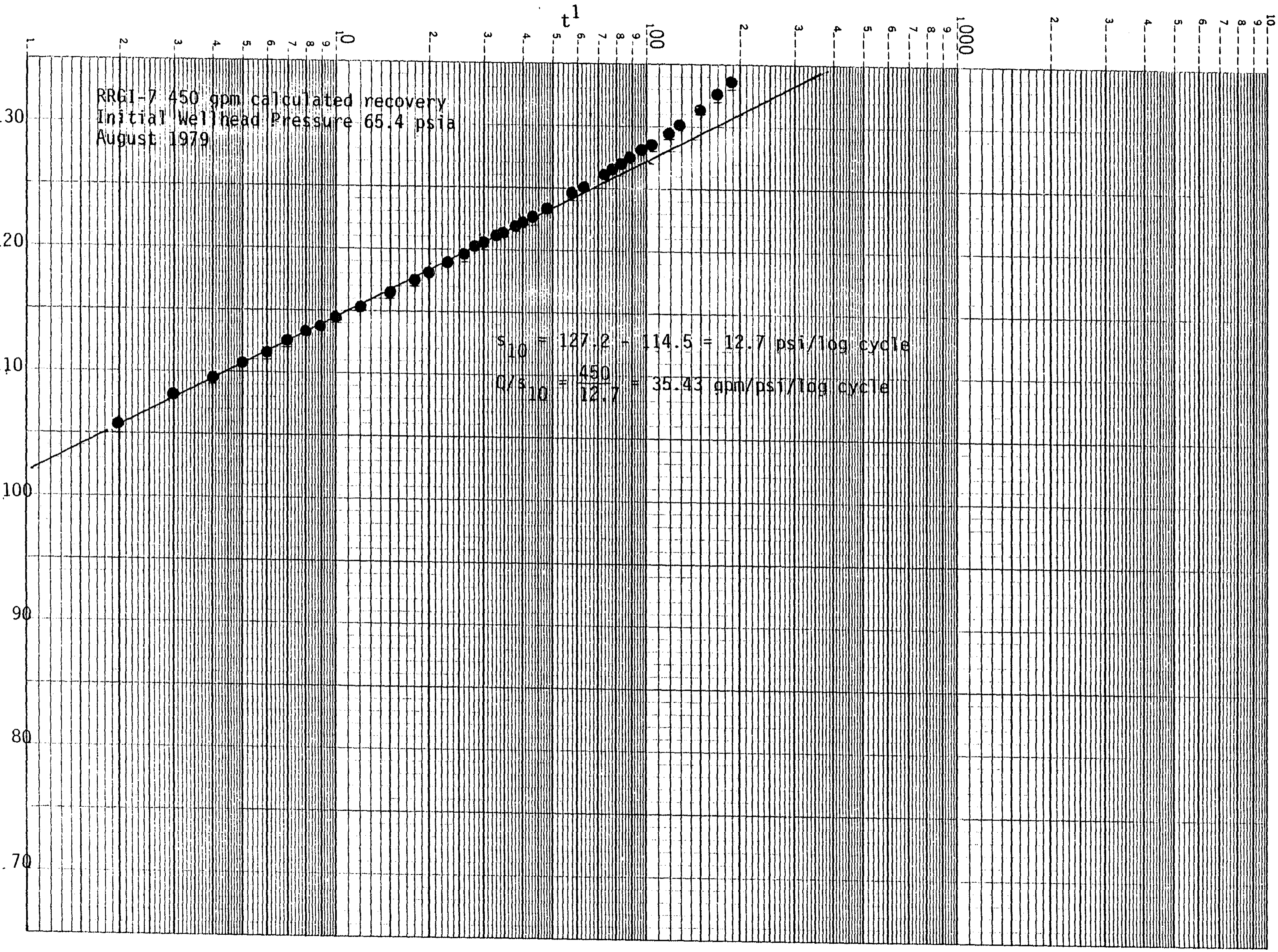
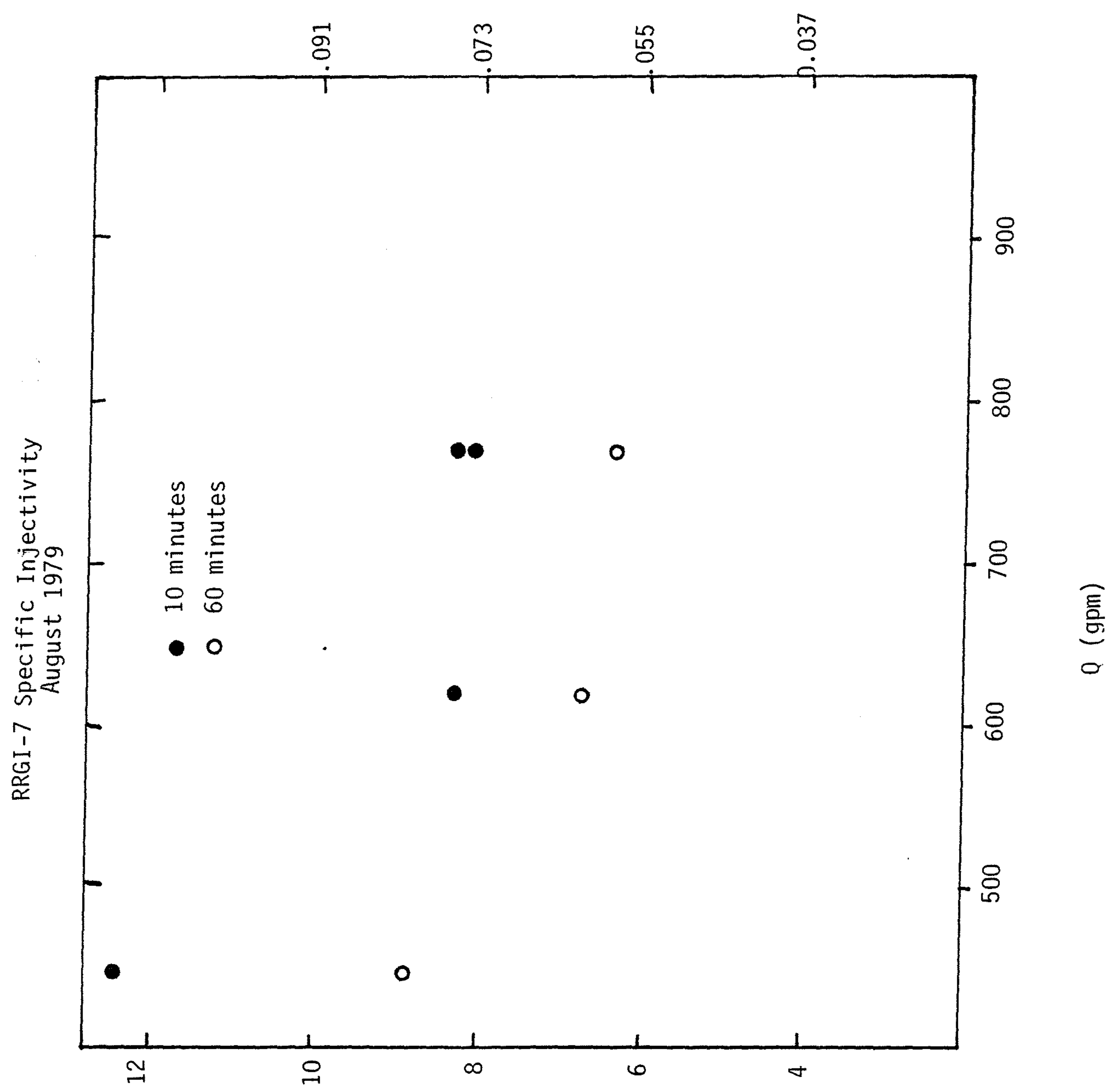


FIGURE 16

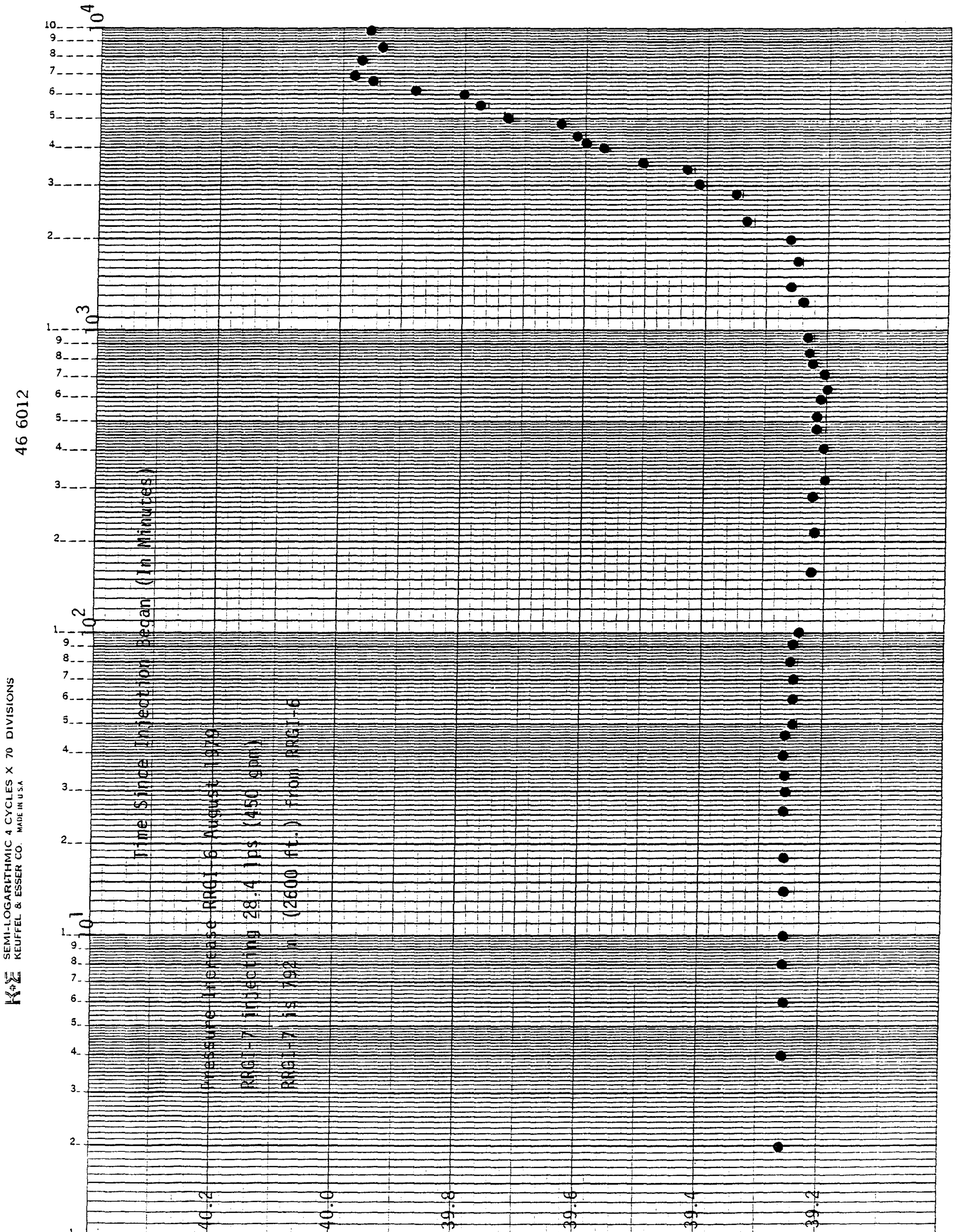
CALCULATED RECOVERY (PSI)

Specific Capacity in lps/kPa



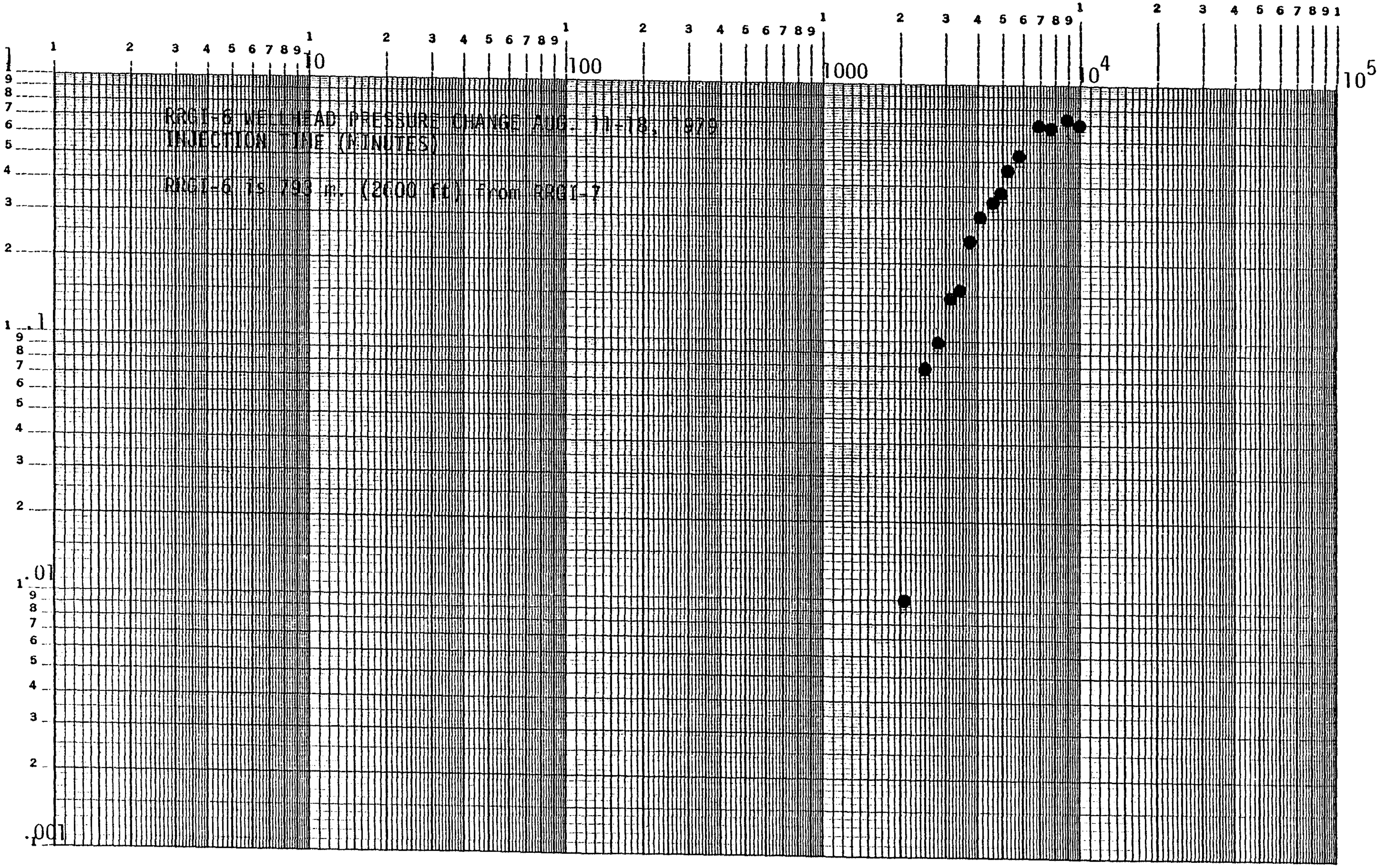
Specific Capacity in gpm/psi

FIGURE 17



Wellhead Pressure (PSI)

FIGURE 18



WELLHEAD PRESSURE INCREASE (PSI)

FIGURE 19

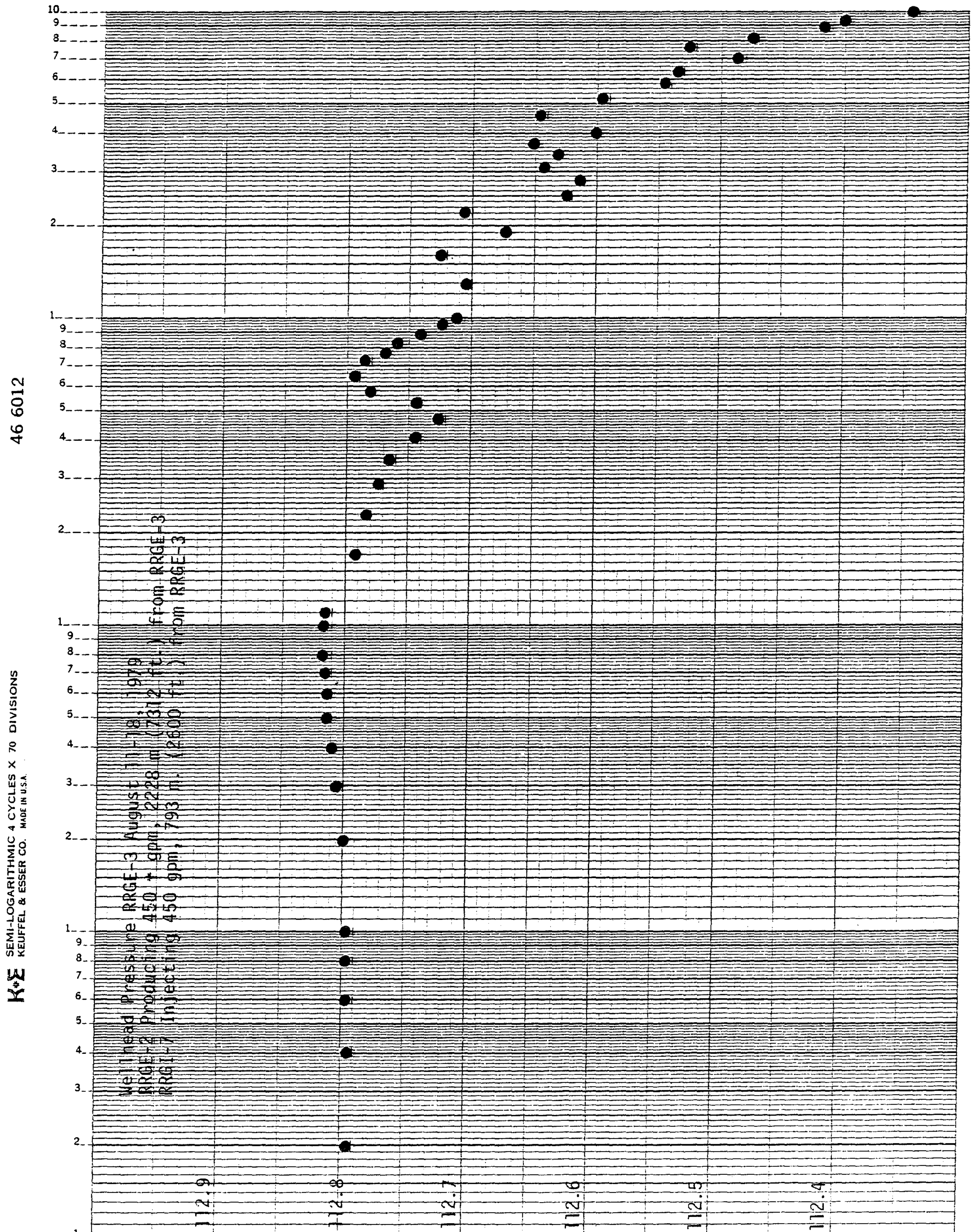


FIGURE 20
WELLHEAD PRESSURE (PSI)

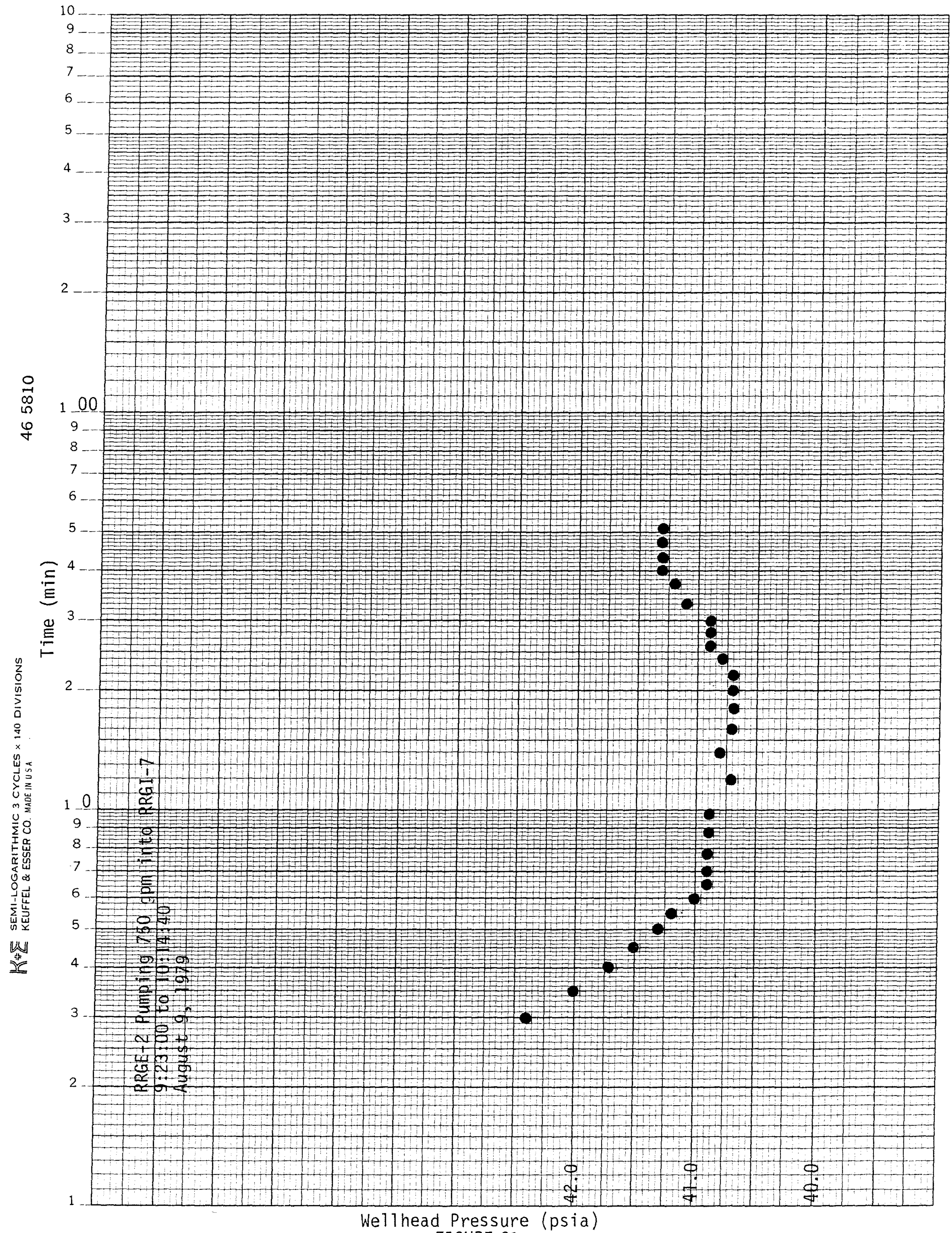

RRGE-2 Pumping 750 gpm into RRGI-7
9:23:00 to 10:14:40
August 9, 1979
Time (min)
42.0
41.0
40.0
Wellhead Pressure (psia)

FIGURE 21

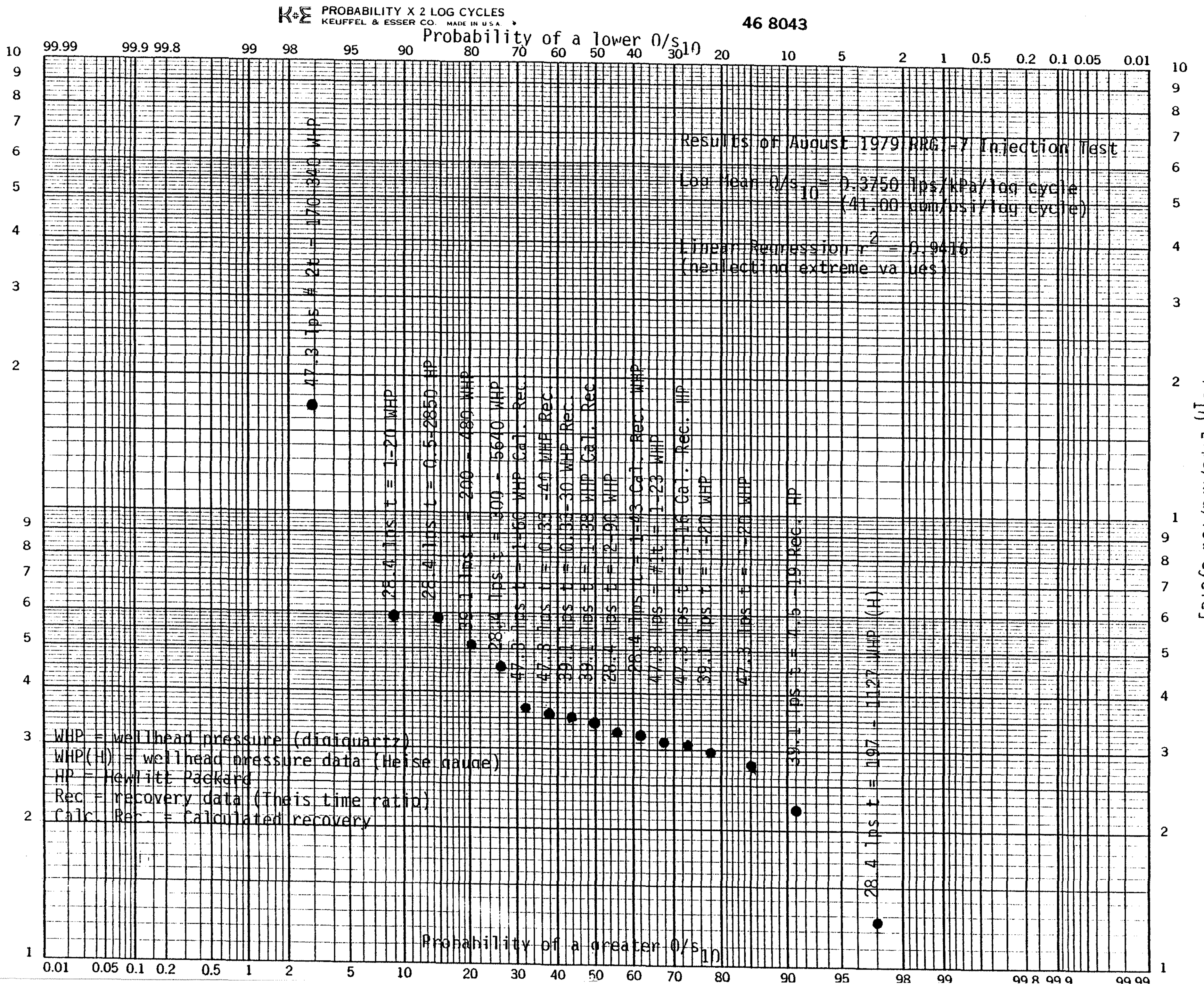

K+E PROBABILITY X 2 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 8043
Probability of a lower Q/s10
Probability of a greater Q/s10
Q/s10 [lps/kPa/log cycle]
Results of August 1979 RRGI-7 Injection Test
Log Mean Q/s10 = 0.3750 lps/kPa/log cycle
(41.00 gpm/psi/log cycle)
Linear Regression r2 = 0.9416
(neglecting extreme values)
47.3 lps # 2t = 170-340 WHP
28.4 lps t = 1-20 WHP
28.4 lps t = 0.5-2850 HP
39.1 lps t = 200 - 480 WHP
28.4 lps t = 300 - 5640 WHP
47.3 lps t = 1-60 WHP Cal. Rec.
47.3 lps t = 0.33 -40 WHP Rec.
39.1 lps t = 0.33-30 WHP Rec.
39.1 lps t = 1-38 WHP Cal. Rec.
28.4 lps t = 2-90 WHP
28.4 lps t = 1-43 Cal. Rec. WHP
47.3 lps = #1t = 1-23 WHP
47.3 lps t = 1-16 Cal. Rec.
39.1 lps t = 1-20 WHP
47.3 lps t = -20 WHP
39.1 lps t = 7.5 - 19 Rec. HP
28.4 lps t = 197 - 1127 WHP (H)
WHP = wellhead pressure (digiquartz)
WHP(H) = wellhead pressure data (Heise gauge)
HP = Hewlitt Packard
Rec = recovery data (Theis time ratio)
Calc. Rec. = Calculated recovery

FIGURE 25