CALCULATION AND USE OF STEAM/WATER RELATIVE PERMEABILITIES IN GEOTHERMAL RESERVOIRS

A MASTER OF SCIENCE REPORT

BY

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June 1978

ABSTRACT

A new method to calculate the steam/water relative permeabilities in geothermal reservoirs was developed and applied to field data from Wairakei in New Zealand. This method has the following characteristics compared to previous methods. This method :

(i) needs the production flow rate history and the wellhead temperature alone,

(ii) evaluates the features of each well separately, and

(iii) decreases the scatter of the points on the calculated relative permeability curves.

Bottomhole values of the parameters are needed for a more accurate determination of relative permeability curves. There are two ways to evaluate bottomhole conditions. One is by calculation, and the other is by measurement. Methods to calculate the pressure drop and the heat loss in the wellbore were demonstrated. In particular, a new method to calculate the heat loss in the wellbore for finite flow rate was developed. It was also determined which parameters should be measured in future field experiments.

Finally, the study showed how to use the resulting relative permeability curves as a basis for analysis of future well tests for geothermal reservoirs.

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I. INTRODUCTION

It was reported by Grant[1] and Horne[2] that the steam/water relative permeabilities in geothermal reservoirs can be estimated from the history of production flow rates and the enthalpy of the fluid. However, in order to get the enthalpy of the fluid, we need to know the pressure and temperature, after which the enthalpy is a function of production flow rate, pressure, and temperature. Therefore, if we know the pressure and temperature of the fluid, we are able to estimate relative permeabilities from the history of production flow rate only.

In this research work, a graphical method to obtain relative permeabilities from the production flow rate history was developed and applied to the field data at Wairakei in New Zealand. This method removed some assumptions which were necessary for the methods of Grant[1] and Horne.[2]

In addition, further studies of wellbore pressure drop and heat loss were performed. These considerations are necessary to extend this method to future geothermal well test experiments that might not have such a long history. For the analysis of wellbore pressure drop, the Govier et **al.**[3] method was applied to the field data, and the results were compared with the actual values. For the analysis of wellbore heat loss, a new method for finite flow rates was developed.[7]

Finally, the relative permeability curves obtained can be used in the derivation of methods of well-test analysis for the steam/water geothermal systems. The foundation of this work was shown.

II. PREVIOUS METHODS OF CALCULATING STEAM/WATER RELATIVE PERMEABILITIES IN GEOTHERMAL RESERVOIRS

Grant[1] and Horne[2] introduced the method to obtain the steam/water relative permeabilities in geothermal reservoirs. Grant made several assumptions, namely:

(i) The temperature of the well is constant and is the same for every well.

(ii) The pressure gradient in the reservoir does not change even if the enthalpy of fluid changes.

(iii) The product of permeability times flowing area is constant.

(iv) Wellhead steam and water discharges are the same as bottomhole values, thus flashing of fluid in rhe wellbore is neglected.

(v) Fluid flows according to Darcy's law.

(vi) Flashing in the reservoir is neglected.

Under these assumptions, Grant derived the following equations:

$$Q_w = \rho_w \cdot \frac{k}{\mu_w} \, k_w \cdot AD' \qquad (1)$$

$$Q_s = \rho_s \cdot \frac{k}{\mu_s} \cdot k_s \cdot Ap' \qquad (2)$$

$$Q = \left(\frac{\rho_w k_w}{\mu_w} + \frac{\rho_s k_s}{\mu_s} \right) kAp' \qquad (3)$$

where p' is the pressure gradient, and from an energy balance:

$$h = \frac{\dfrac{\rho_w k_w h_w}{\mu_w} + \dfrac{\rho_s k_s h_s}{\mu_s}}{\dfrac{\rho_w k_w}{\mu_w} + \dfrac{\rho_s k_s}{\mu_s}} \qquad (4)$$

Grant plotted Q vs h (see Fig. 1), then, assuming that $kAp' \equiv B$ was constant for each well, and scaling each well by an estimated B so that all the points lay on the same "curve," he extrapolated the pure water point, Q_0, from the graph.

At the pure water point, F_w is unity, so that from Eq. 1:

$$Q_0 = \frac{\rho_w}{\mu_w} \cdot B \qquad (5)$$

Thus, for any point:

$$\frac{Q}{Q_0} = k_w + k_s \left(\frac{\rho_s \mu_w}{\rho_w \mu_s} \right) \qquad (6)$$

and:

$$h \left(\frac{\rho_w k_w}{\rho_w} + \frac{\rho_s k_s}{\rho_s} \right) = \frac{\rho_w k_w h_w}{\rho_w} + \frac{\rho_s k_s h_s}{\rho_s} \qquad (7)$$

As Grant assumed that temperature was constant and the same for every well, the thermodynamic variables, ρ_w, ρ_s, μ_w, μ_s, h_w, and h_s, were also constant. Therefore, Eqs. 6 and 7 are two linear equations for the two unknowns k_w and k_s. The relative permeabilities, k_w and k_s, can be found by solving these two equations simultaneously.

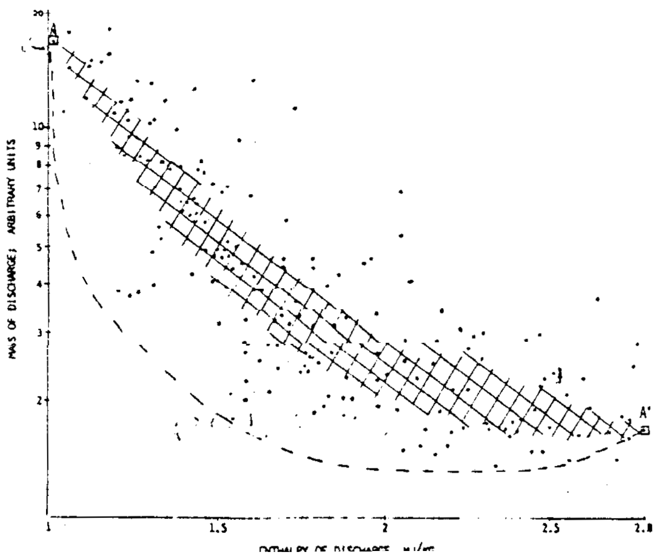

FIG. 1: Q vs h GRAPH (GRANT[1])

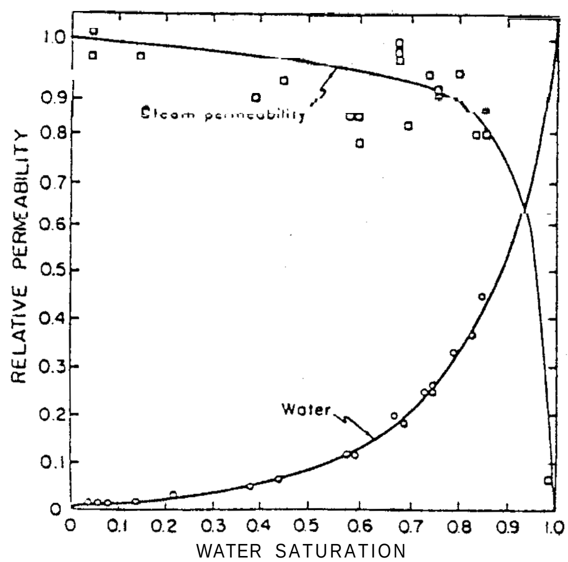

FIG. 2: STEAM-WATER RELATIVE PERMEABILITIES FROM WAIRAKEI WELL DATA (HORNE[2])

Horne[2] suggested that the production flow rate should be taken at bottomhole conditions, and that the total production flow rate should be divided by the wellhead pressure in order to smooth the effect of pressure change as the well ages. Horne also recommended use of the actual bottomhole temperature, density, viscosity, and enthalpy. He applied his improved method under these conditions to the field data from Wairakei in New Zealand. **He** obtained a pair of relative permeability curves, shown in Fig. 2. The water saturation in this analysis is based on a mass ratio rather than the more usual volume ratio.

III. NEW METHOD TO CALCULATE STEAM/WATER RELATIVE PERMEABILITIES

As enthalpy is a function of production flow rate, pressure, and temperature, if one knows pressure and temperature, enthalpy is unnecessary to obtain relative permeabilities. In other words, only production flow rate history, pressure, and temperature are needed to calculate steam/water relative permeabilities in this new method. This is convenient for field data analysis.

Also, we can remove some of the assumptions which Grant' made, thus:

(i) Temperature need not be the same for every well.

(ii) The product of pressure gradient, permeability, and flowing area can be calculated explicitly, and thus need not be estimated graphically in Grant's procedure.

The removal of these assumptions is important, as it decreases the variability of the calculated results. That is, we can consider each well's condition explicitly in this method.

Assumptions used for a preliminary test of this new method are summarized here.

(i) The pressure gradient is constant for a short time for each well. (Although unnecessary for the data used in the preliminary test, we can remove this assumption. This will be discussed in Section IV.)

(ii) The product of permeability and flowing area is constant for each well.

(iii) Wellhead steam and water discharges are the same as bottomhole values, thus neglecting flashing of fluid in the wellbores. (The effect of making this assumption is small in the case considered here, and we can, if necessary, remove this assumption also. This will be discussed in Section IV.)

(iv) Fluid flows following Darcy's law.

(v) Flashing in the reservoir is neglected.

Under these assumptions and from Darcy's law:

$$Q_w = \rho_w \cdot \frac{k}{\mu} \cdot k_w \cdot Ap' \qquad (1)$$

$$Q_s = \rho_s \cdot \frac{k}{\mu} \cdot k_s \cdot Ap' \qquad (2)$$

then:

$$\frac{Q_w}{Q_s} = \left(\frac{\nu_w}{\nu_s}\right)\left(\frac{k_w}{k_s}\right) \qquad (8)$$

and:

$$Q = \left(\frac{\rho_w k_w}{\mu_w} + \frac{\rho_s k_s}{\mu_s}\right) kAp' = \left(\frac{k_s}{\nu_s}\right)\left[1 + \left(\frac{Q_w}{Q_s}\right)\right] Up' \qquad (9)$$

Since kAp' is constant for each well in the simplest case, and since Q vs Q_w/Q_s is almost linear when Q_w/Q_s is small (because k_s is nearly constant and equal to unity for low water saturations), we can find Up' from either the intercept or the gradient of the line on the graph Q vs Q_w/Q_s, smoothed using the least squares method. Even if Q_w/Q_s is not small, and Q vs Q_w/Q_s is not linear, we can find kAp' from the intercept of the graph

Q vs Q_w/Q_s by curve fitting. If the value of Q at the intercept $Q_w/Q_s = 0$ is Q*, then:

$$Q^* = \frac{1}{\nu_s} \cdot kAp' \tag{10}$$

Because $k_s = 1$ at $Q_w = 0$, then, substituting Eq. 10 into Eqs. 1 and 2:

$$k_w = \left(\frac{\nu_w}{\nu_s}\right)\left(\frac{Q_w}{Q^*}\right) \tag{11}$$

and:

$$k_s = \frac{Q_s}{Q^*} \tag{12}$$

From Eqs. 11 and 12, relative permeabilities k_w, k_s can be computed if we know Q_w, Q_s, Q*, ν_w, and ν_s. Of course, Q*, ν_w, and ν_s are different for each well.

This method was applied to the field data from Wairakei in New Zealand. Figures 3-7 show the production flow rate histories for five typical wells. Only the data between 1968 and 1970 were used in order to make the use of the assumption of constant pressure gradient reasonable. Figures 8-17 show the Q vs Q_w/Q_s graphs, including the least-square fitted line used to determine Q*, and inferred relative permeability curves for each well. Figure 18 shows the relative permeability curves obtained when every point is plotted on the same graph. In this analysis, water saturation is based on the flowing mass ratio, because the flowing volumetric ratio is small for the field data. Volumetric water saturation cannot be obtained from the flowing volume ratio because (1) gas and liquid velocities are unknown, and (2) the immobile water saturation is unknown. In the petroleum industry, reservoir fluid saturations are usually estimated from material balance considerations. In Fig. 18, the immobile

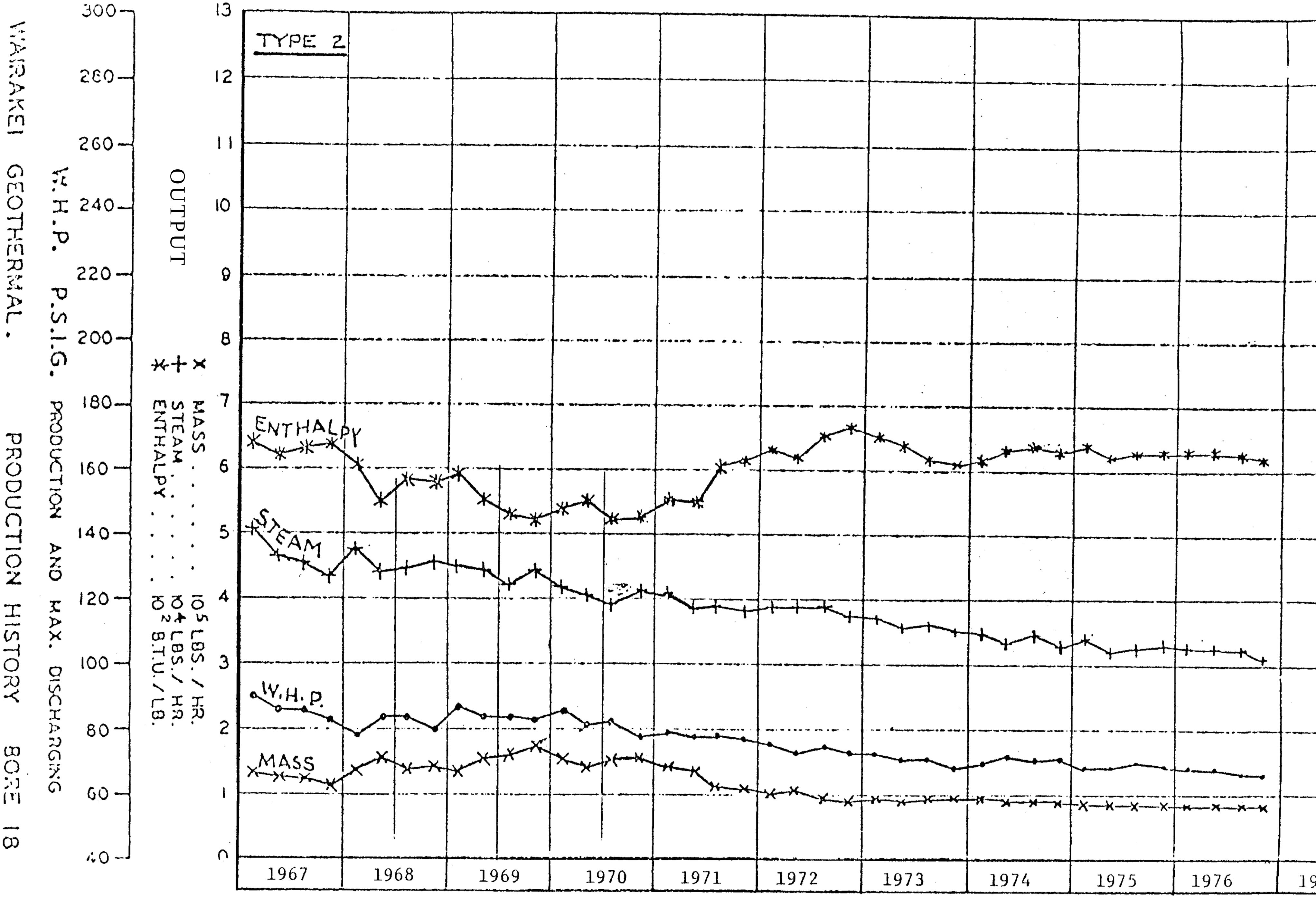

FIG. 3: PRODUCTION HISTORY OF WELL 18

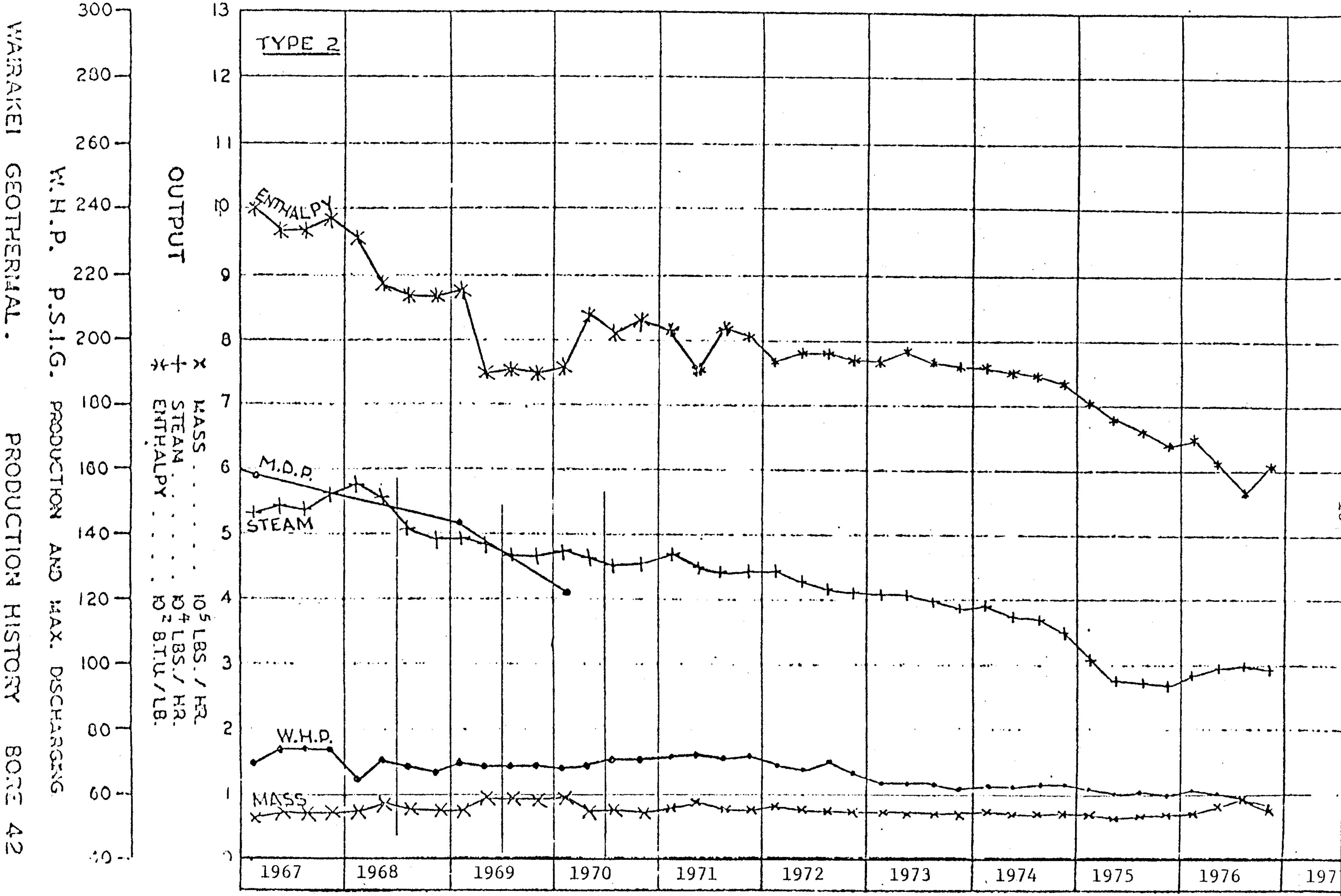

FIG. 4: PRODUCTION HISTORY OF WELL 42

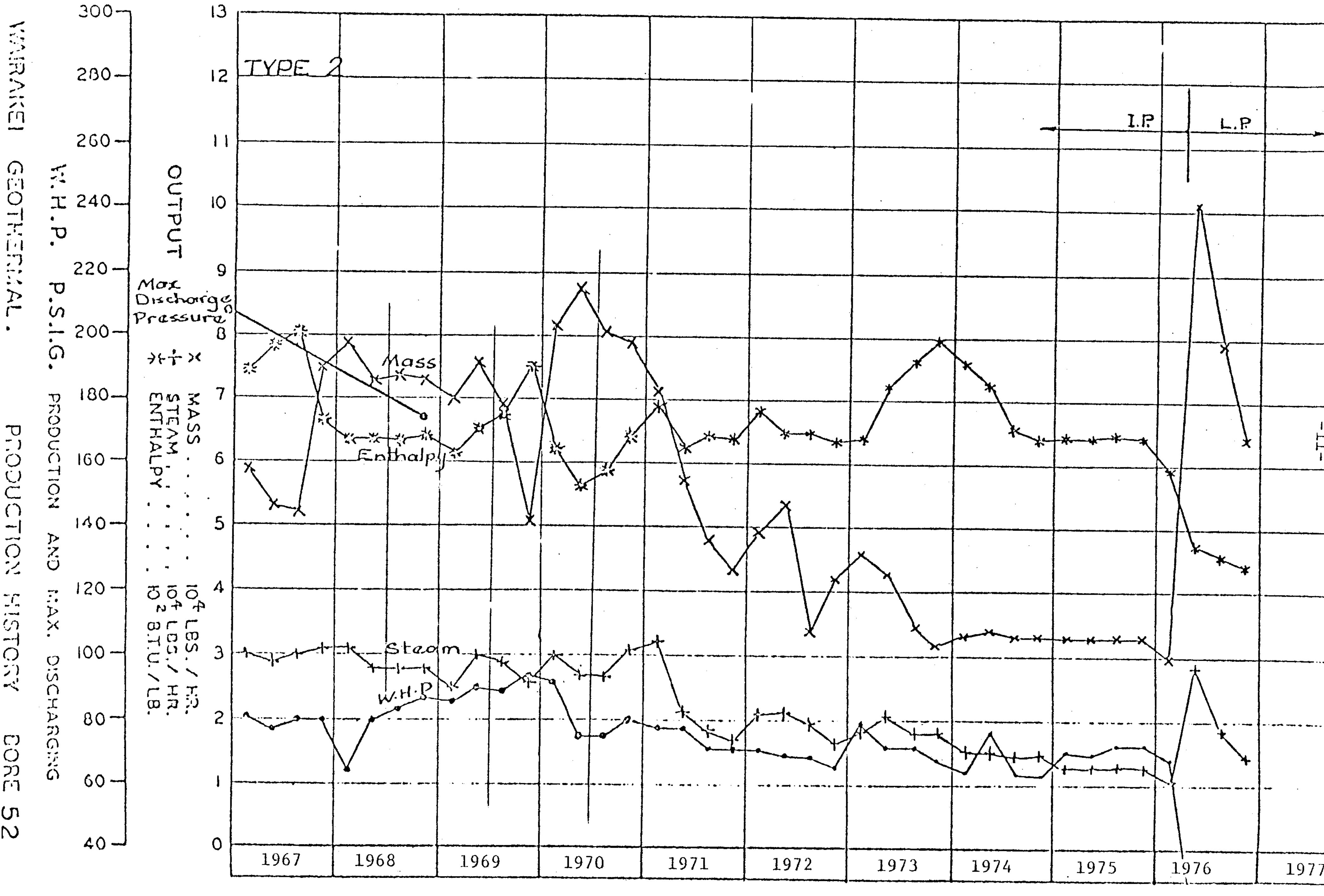

FIG. 5: PRODUCTION HISTORY OF WELL 52

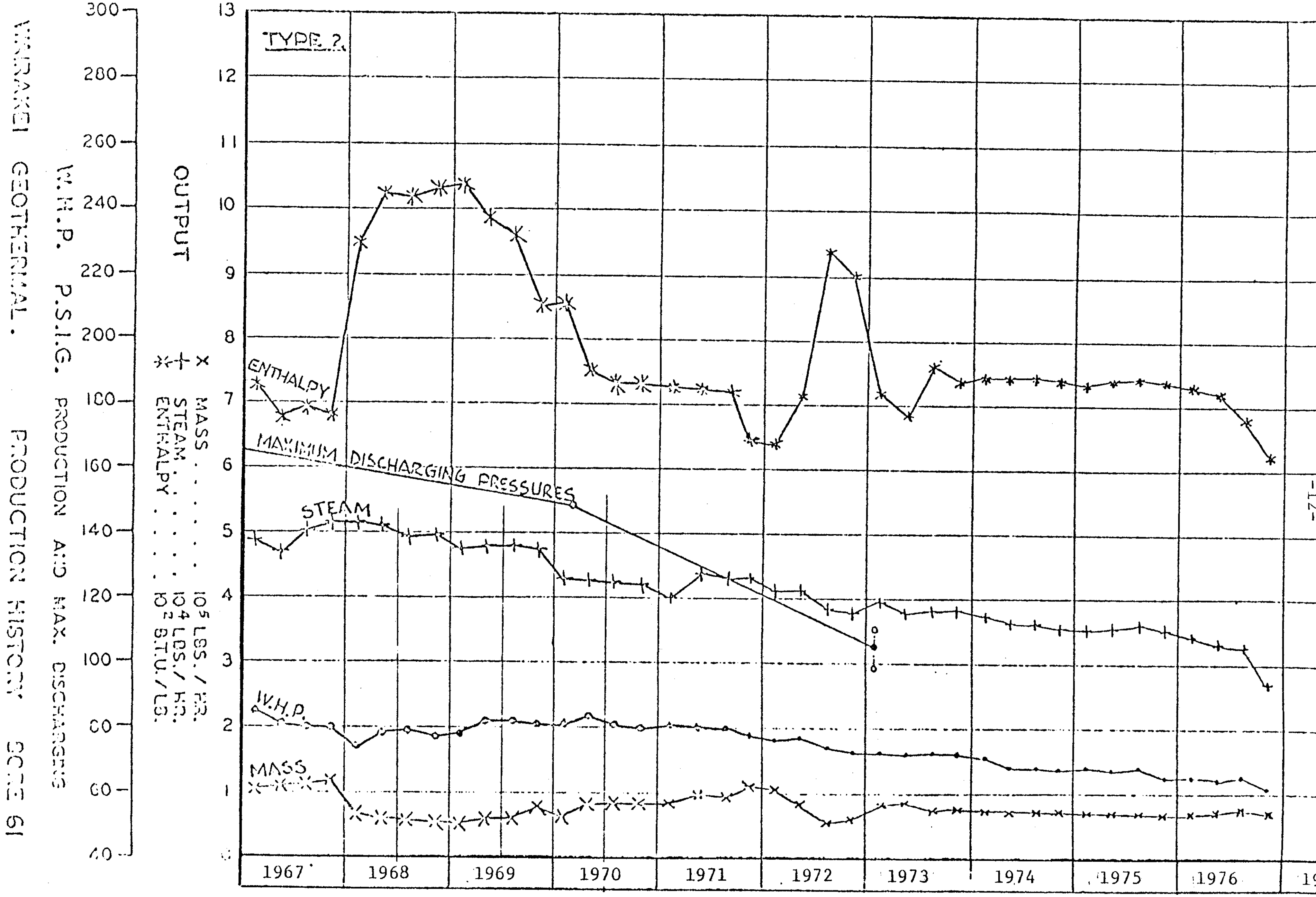

FIG. 6: PRODUCTION HISTORY OF WELL 61

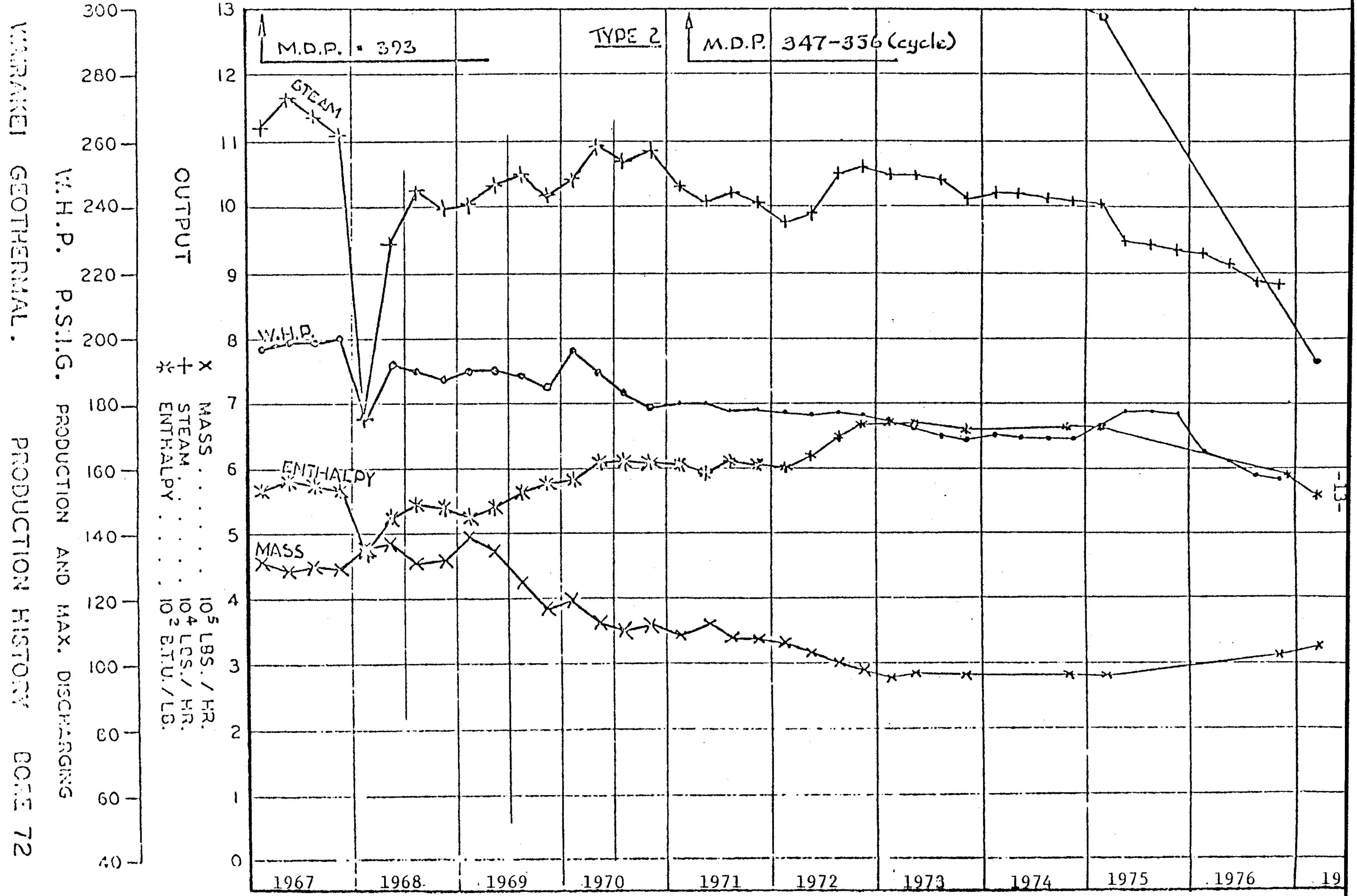

FIG. 7: PRODUCTION HISTORY OF WELL 72

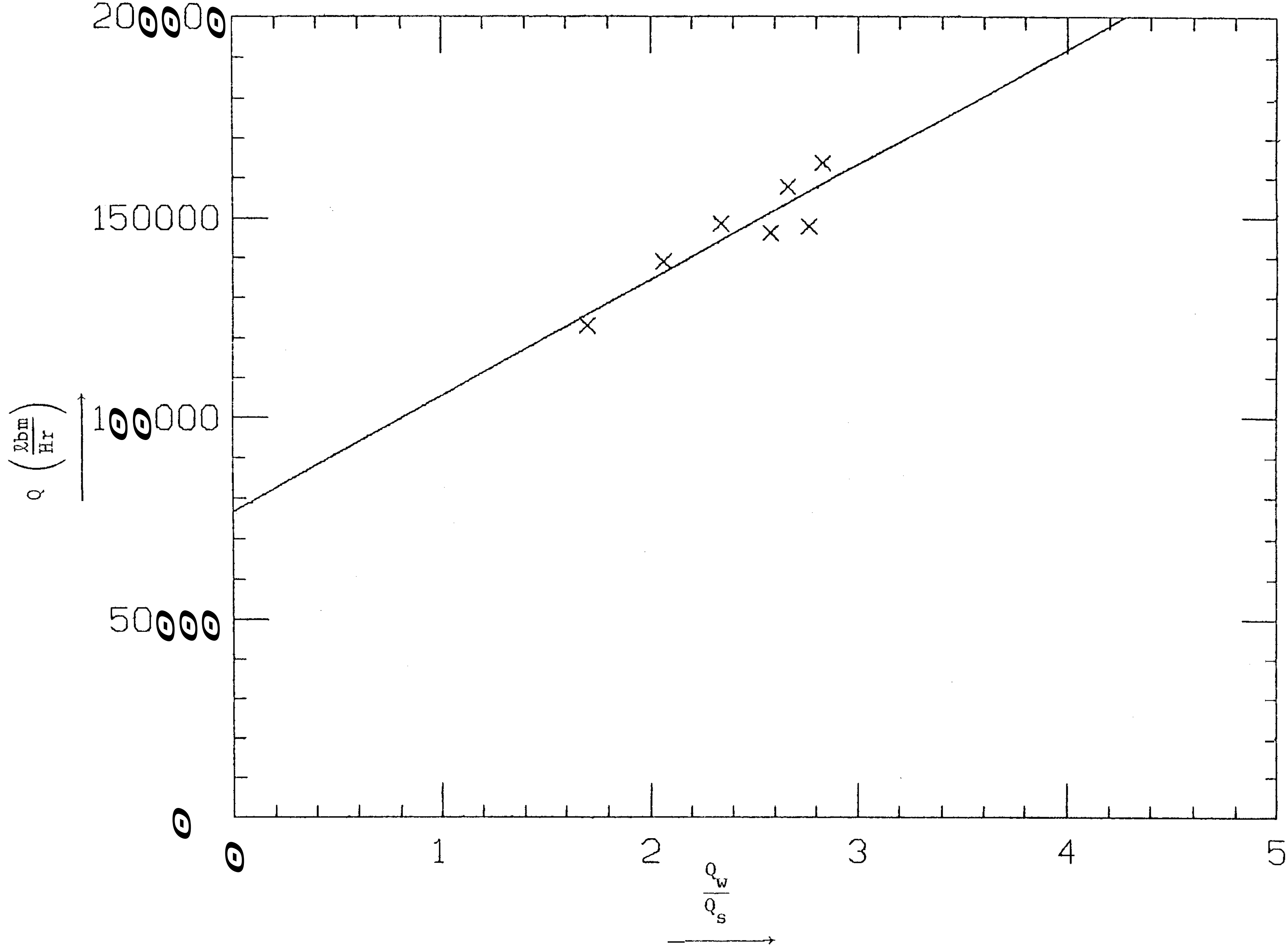

FIG 8: Q vs Q_w/Q_s OF WELL 18

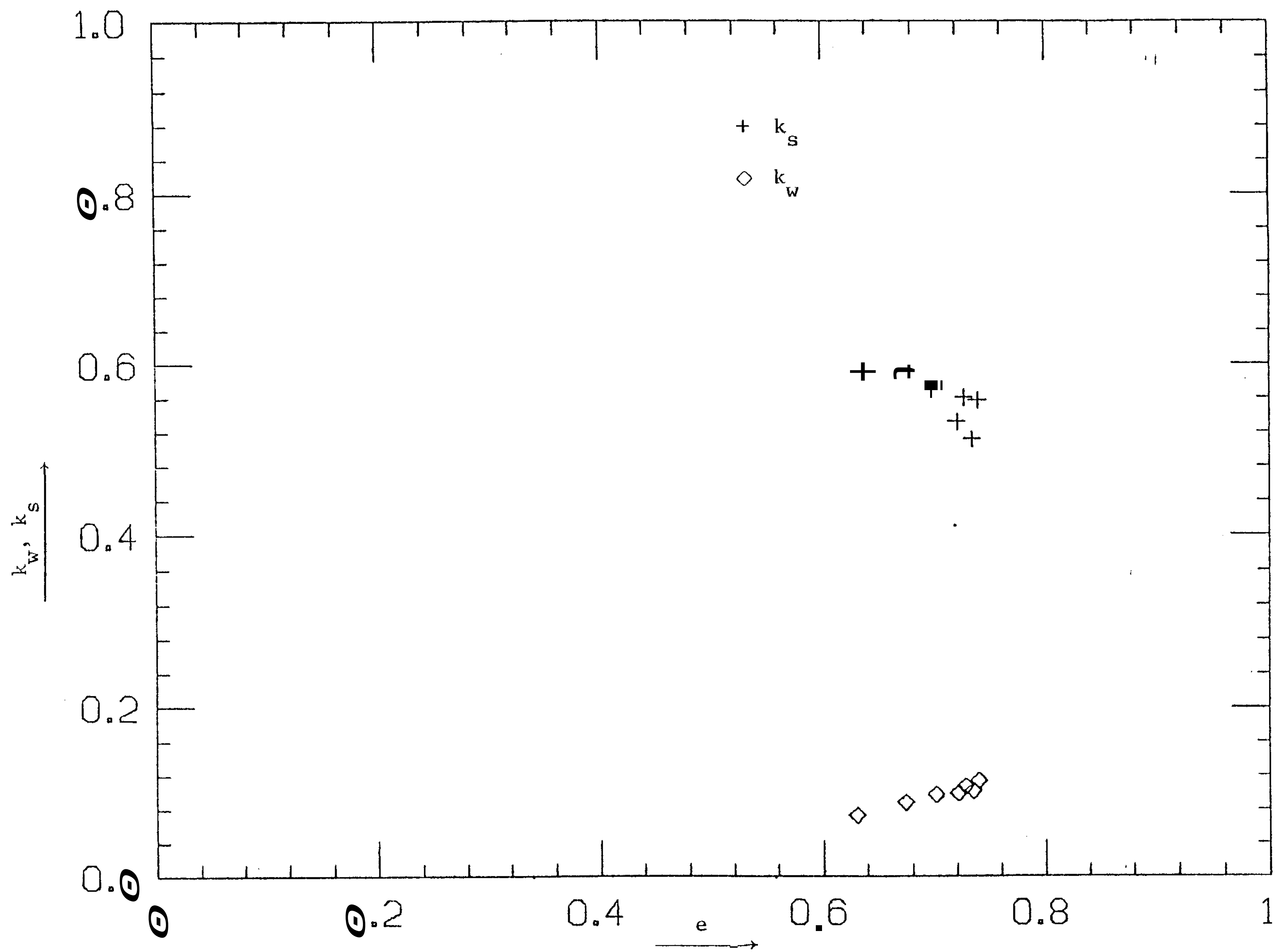

FIG 9: RELATIVE PERMEABILITY OF WELL 18

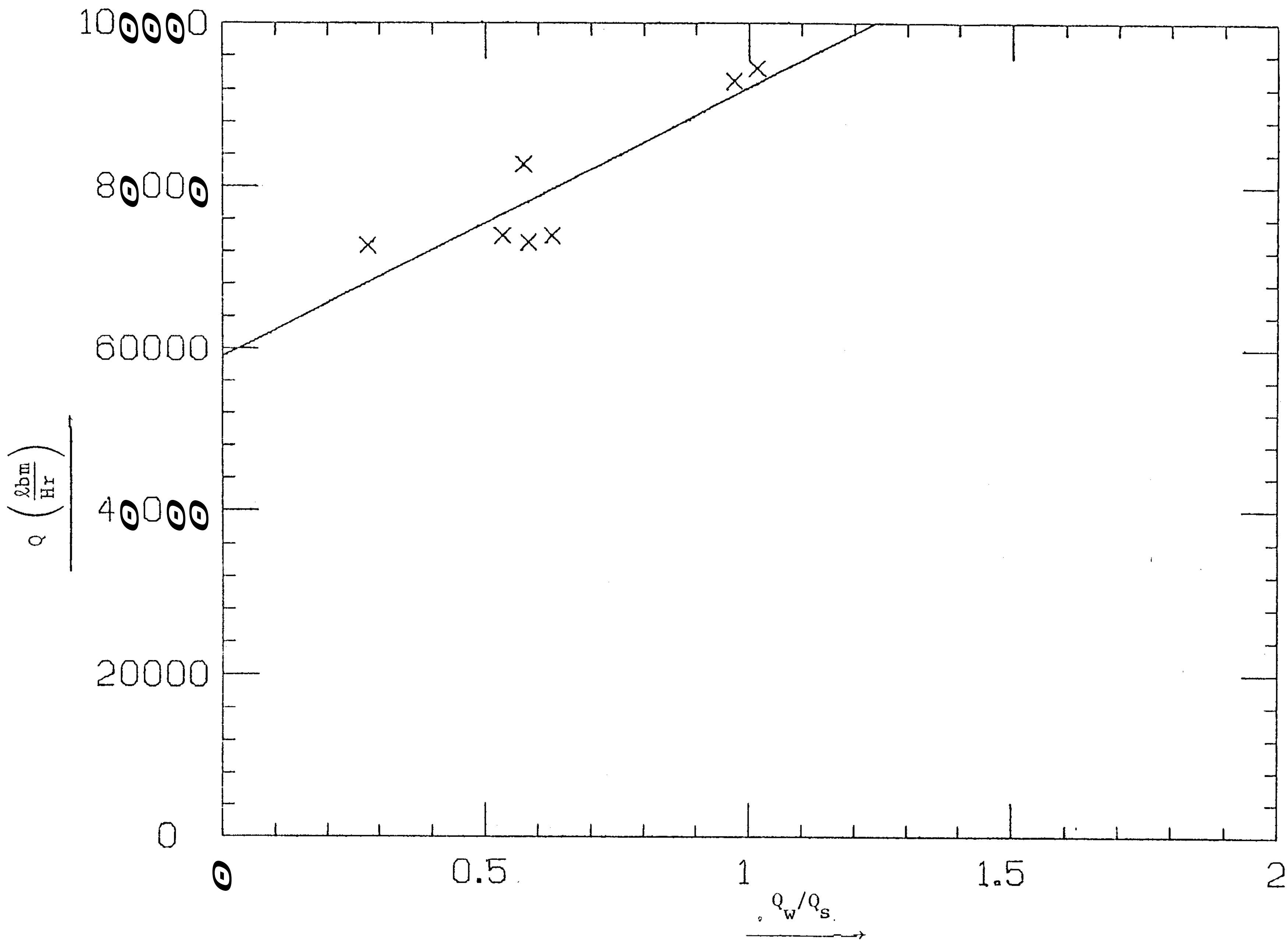

FIG. 10: Q VS Q_w/Q_s OF WELL 42

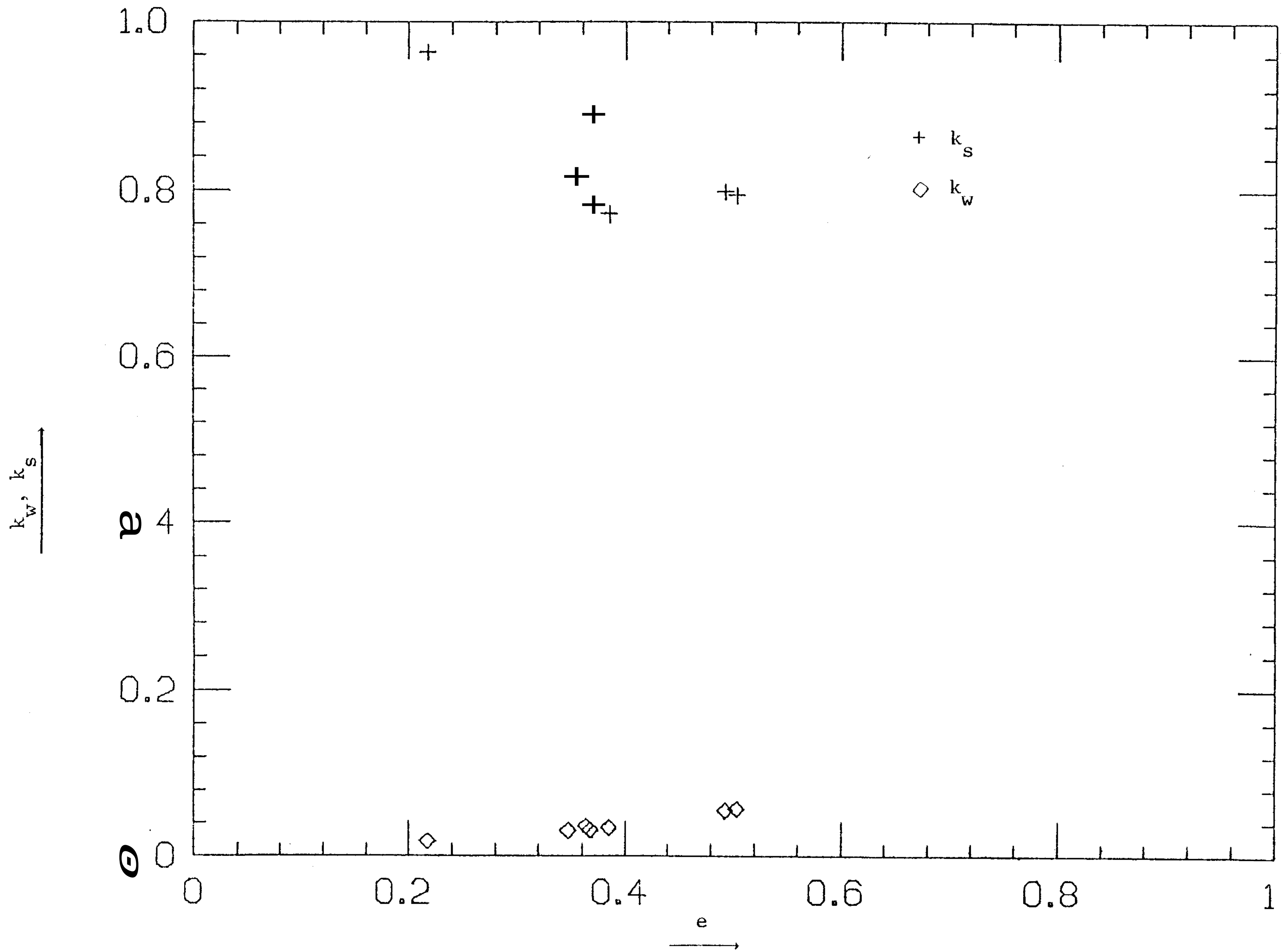

FIG. 11: RELATIVE PERMEABILITY OF WELL 42

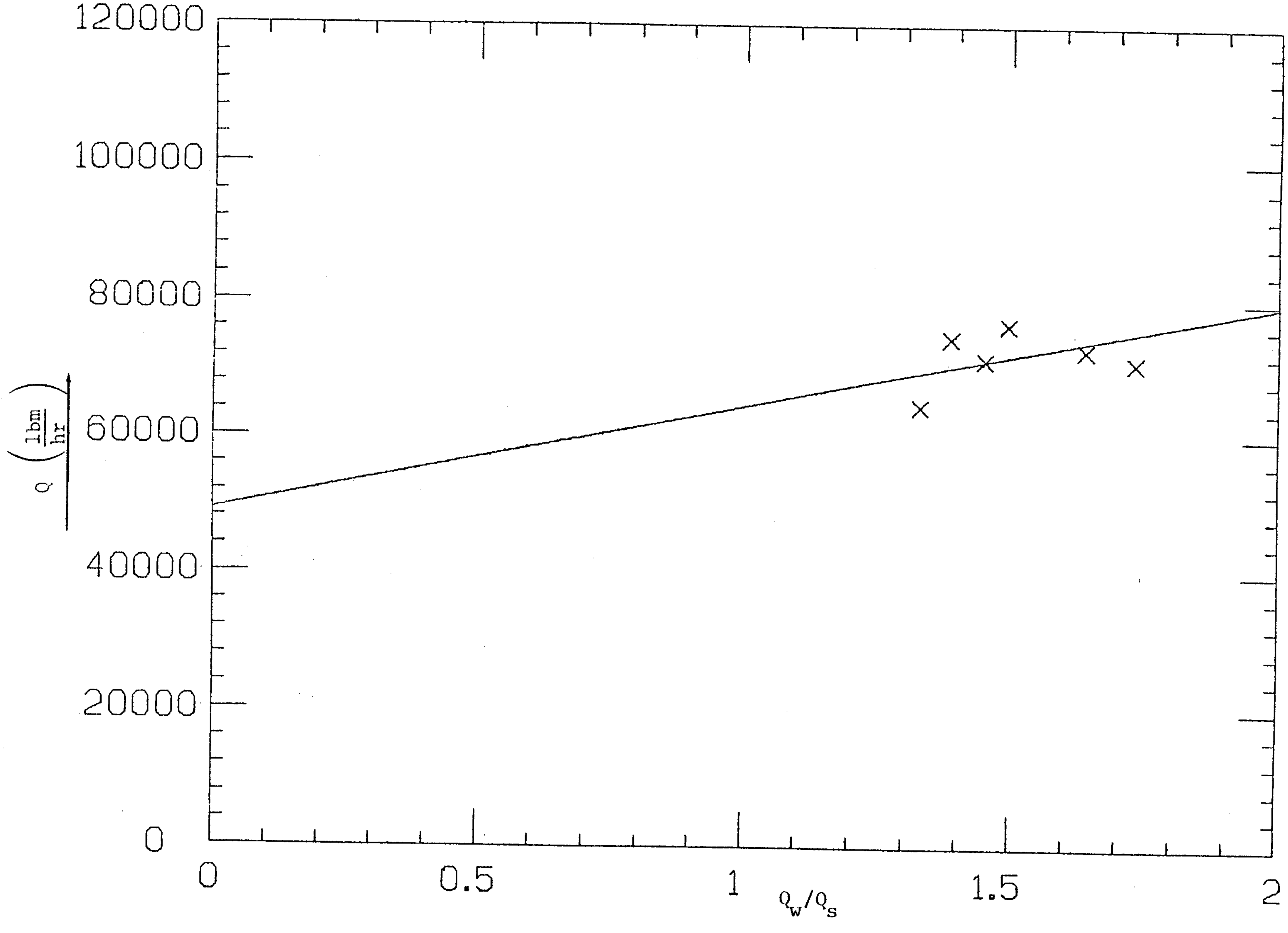

FIG. 12: Q VS Q_w/Q_s OF WELL 52

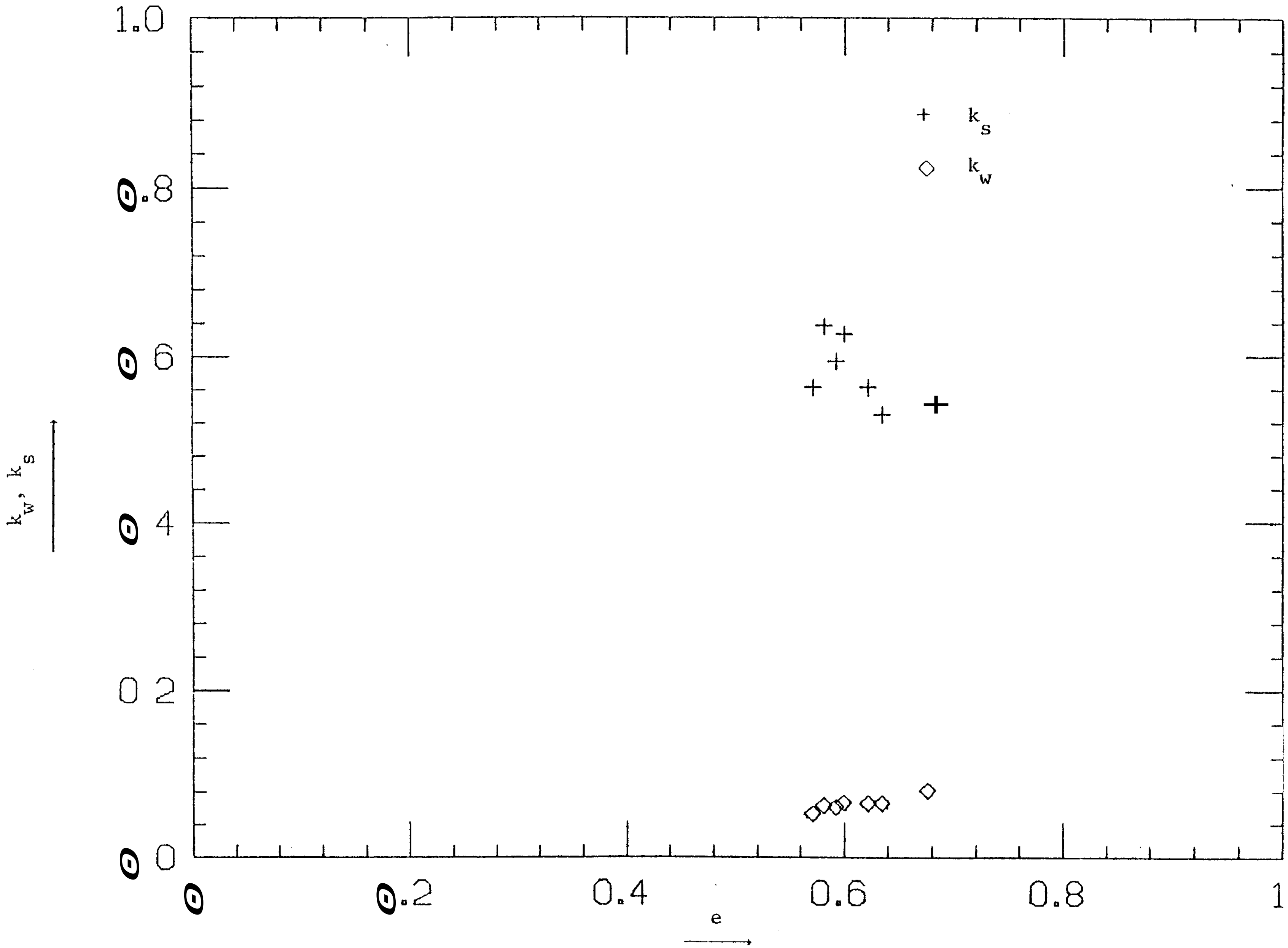

FIG. 13: RELATIVE PERMEABILITY OF WELL 52

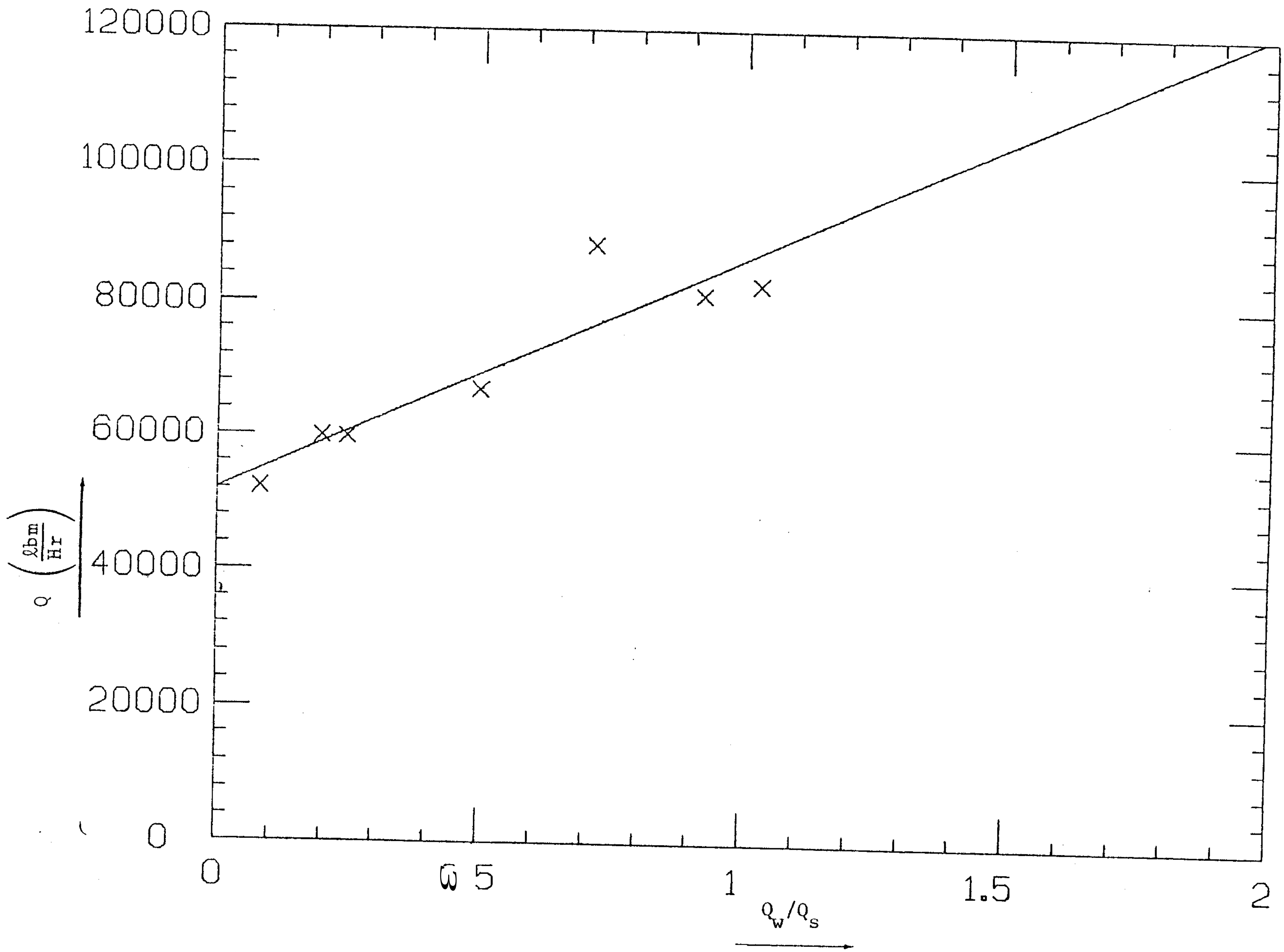

FIG. 14: Q VS Q_w/Q_s OF WELL 61

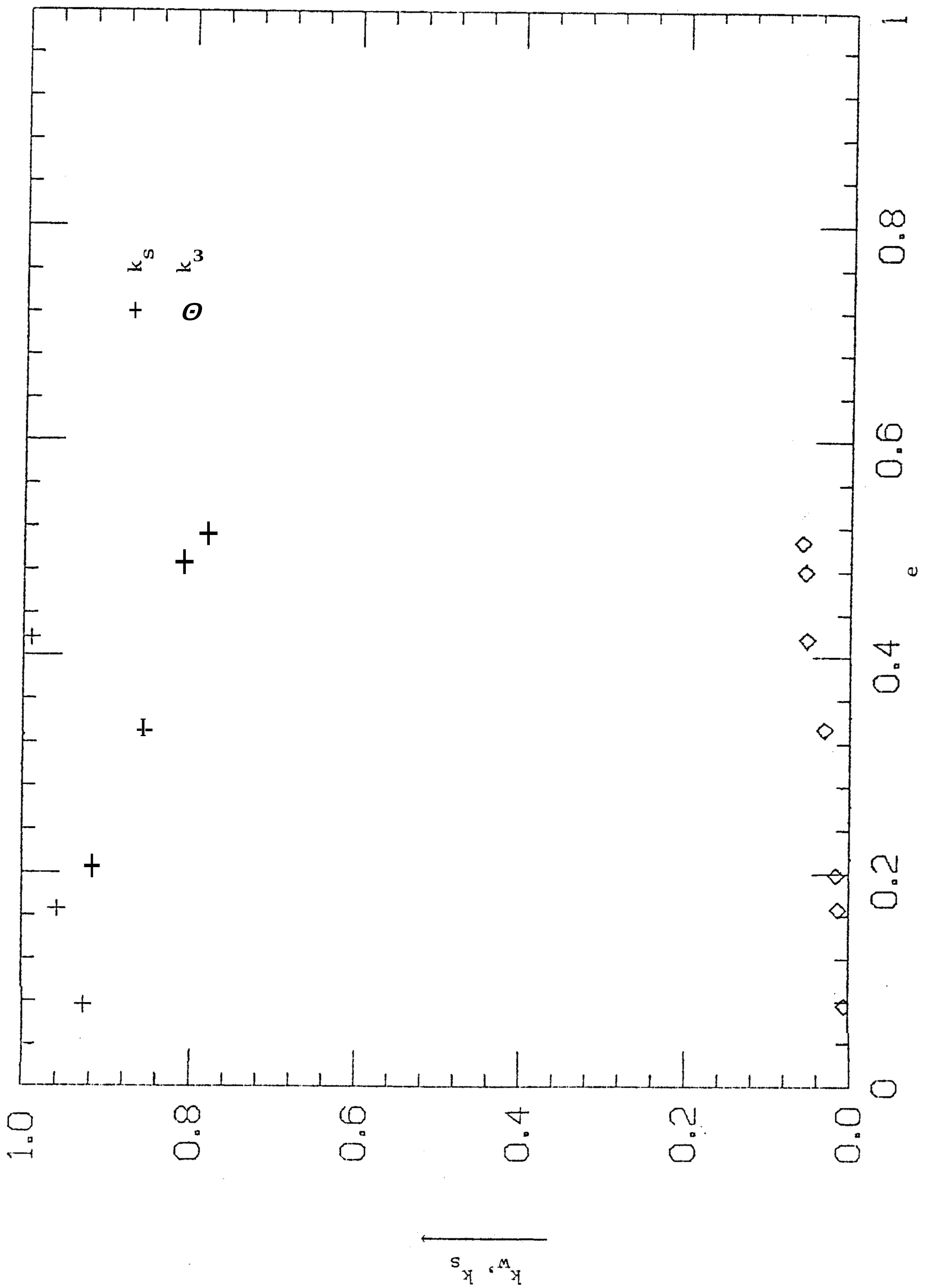

FIG. 15: RELATIVE PERMEABILITY OF WELL 61

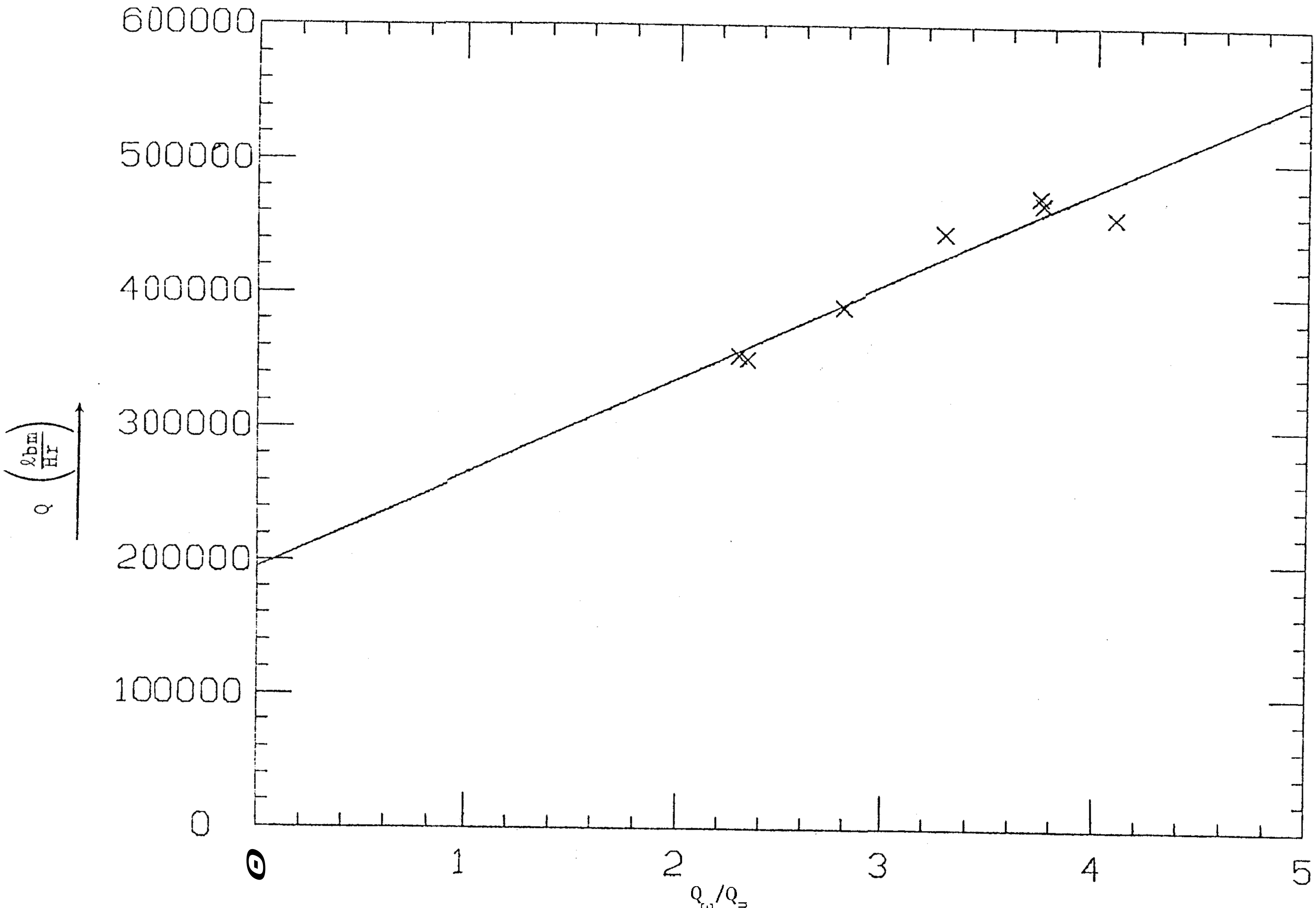

FIG. 16: Q VS Q_w/Q_s OF WELL 72

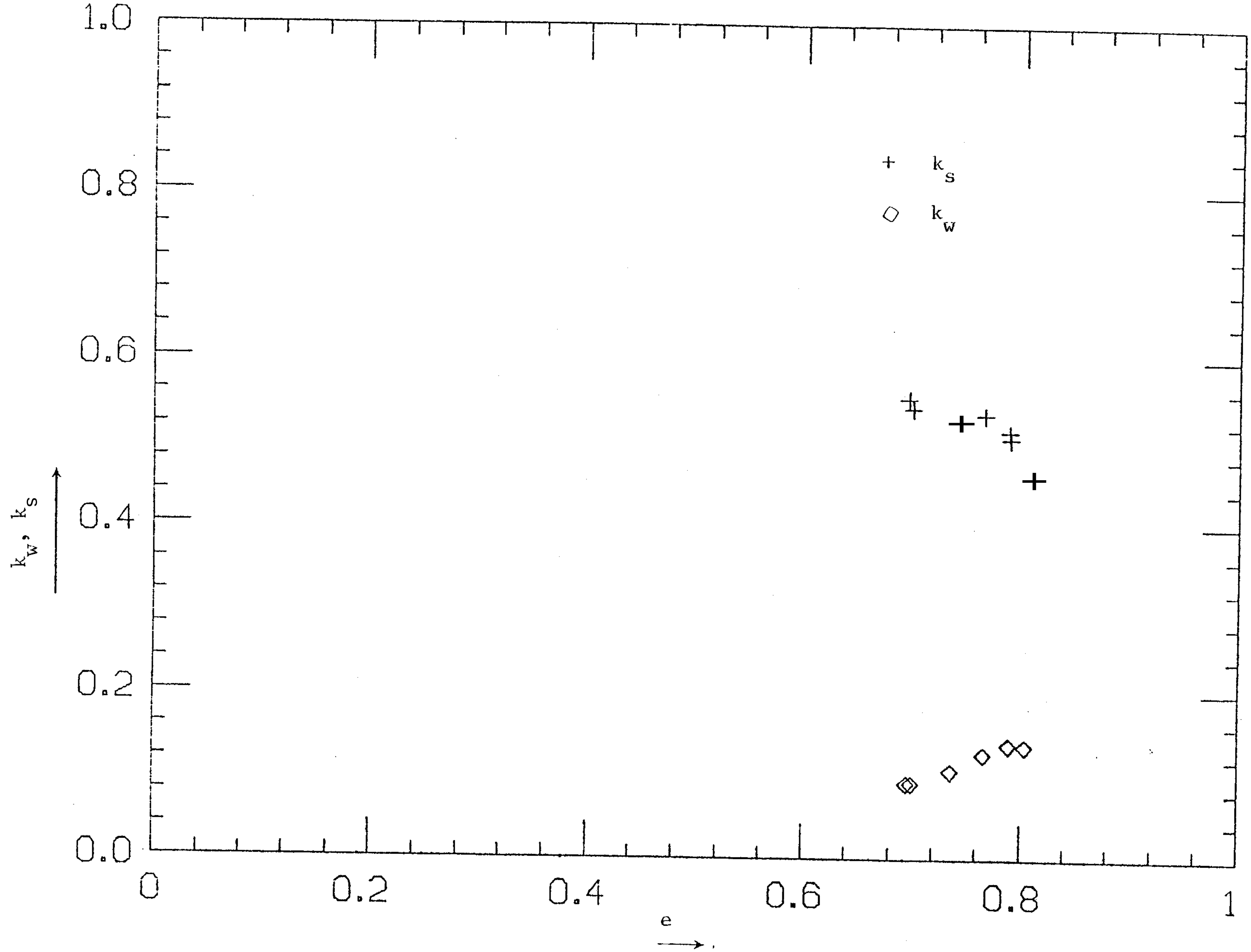

FIG. 15: RELATIVE PERMEABILITY OF WELL 52

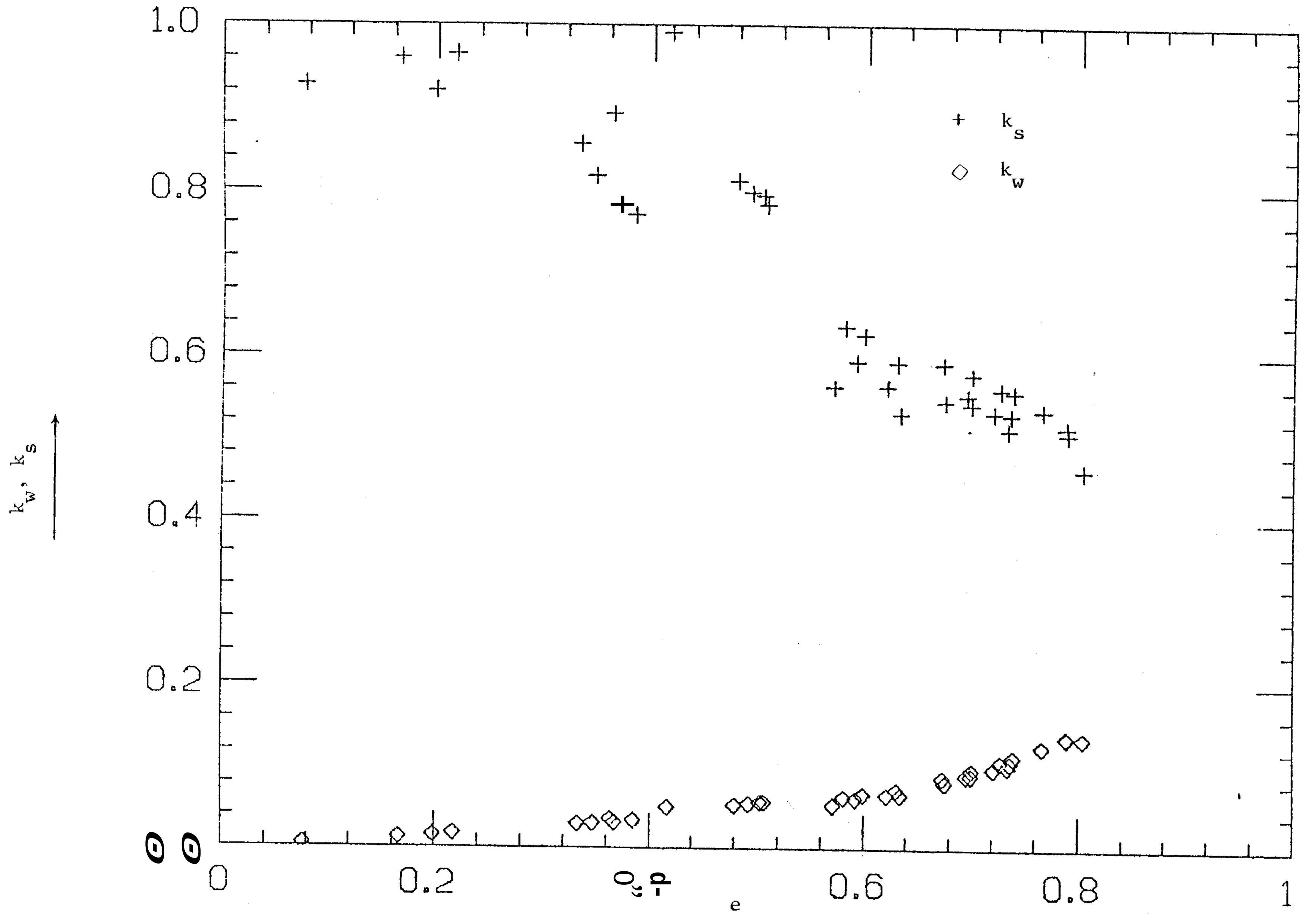

FIG. 18: RELATIVE PERMEABILITY OF EVERY WELL

water saturation is not considered in this illustration. The relative permeabilities obtained for each well agree closely and form a single curve.

The operational procedure for this method of calculating relative permeabilities is summarized below as Method A.

METHOD **A**

Well Data Required:	Water Discharge Q_w Steam Discharge Q_s Temperature T	at well head
Well Data Inferred:	Steam Viscosity μ Water Viscosity μ^s_w	

Procedure:

(1) For each well, plot (Q_w+Q_s) vs Q_w/Q_s on normal Cartesian graph paper.

(2) Extrapolate the data to the $Q_w/Q_s=0$ axis to obtain Q*.

(3) For each of the data points, evaluate k_w and k_s from Eqs. **11** and 12.

(4) Combine the separate well results.

IV. DESIGN OF AN OPERATIONAL TEST TO OBTAIN MORE ACCURATE ESTIMATES

If one can assume that wells are operated for a long time and that the reservoir has reached steady-state or pseudo-steady state, then for a radial system:

$$Q_w = \frac{2\pi\rho_w k k_w h(\bar{p}-p_{BH})}{\mu_w\left[\ell n(\frac{r_e}{r_w})-\alpha\right]} \qquad (13)$$

$$Q_s = \frac{2\pi\rho_s k k_s h(\bar{p}-p_{BH})}{\mu_s\left[\ell n(\frac{r_e}{r_w})-\alpha\right]} \qquad (14)$$

$$\alpha = \begin{cases} \frac{1}{2} & \text{for steady state} \\ \frac{3}{4} & \text{for pseudo-steady state} \end{cases}$$

The influence of operational conditions of the wells and the effect of the change in average reservoir pressure with time can be eliminated by dividing Q by $(\bar{p} - p_{BH})$

Thus, if:

$$C = \frac{2\pi kh}{\ell n(\frac{r_e}{r_w})-a} \qquad (15)$$

then:

$$\frac{Q}{\bar{p}-p_{BH}} = \left(\frac{k_s}{\nu_s}\right)\left[1 + \left(\frac{Q_w}{Q_s}\right)\right] C \qquad (16)$$

and:

$$\frac{Q_w}{Q_s} = \left(\frac{\nu_s}{\nu_w}\right)\left(\frac{k_w}{k_s}\right) \qquad (17)$$

Thus, we can find C from the intercept of the graph $Q/(\bar{p}-p_{BH})$ vs Q_w/Q_s.

In order to use this method, reliable $\bar{p}$ and p_{BH} values are needed. Furthermore, for accurate calculation of relative permeabilities, as Horne suggested,[2] we should use bottomhole values of Q_w and Q_s. However, to do so in cases where there are no available measured bottomhole values, we would have to calculate the pressure drop and heat loss in the wellbore considering flashing of fluid. Flashing, two-phase flow calculations are not easy. Even if the flashing of fluid in the wellbore were neglected, the pressure calculation must evaluate a two-phase vertical pressure drop. To investigate the possibility of doing this, the Govier et al. method[3] was applied to the field data. Figure 19 shows the results of bottomhole pressure calculations in well 72. The calculations indicate that the flow regime is an annular mist flow. The effective depth of the well was assumed to be 1,000 ft from the match point of the measured bottomhole pressure and calculated bottomhole pressure in 1967, which is the only year for which we have data for both measured bottomhole pressure and wellhead pressure. As a matter of fact, the casing program of the well shows casing of 7.2 inch diameter down to 902 ft, and 5.5 and 2.25 inch

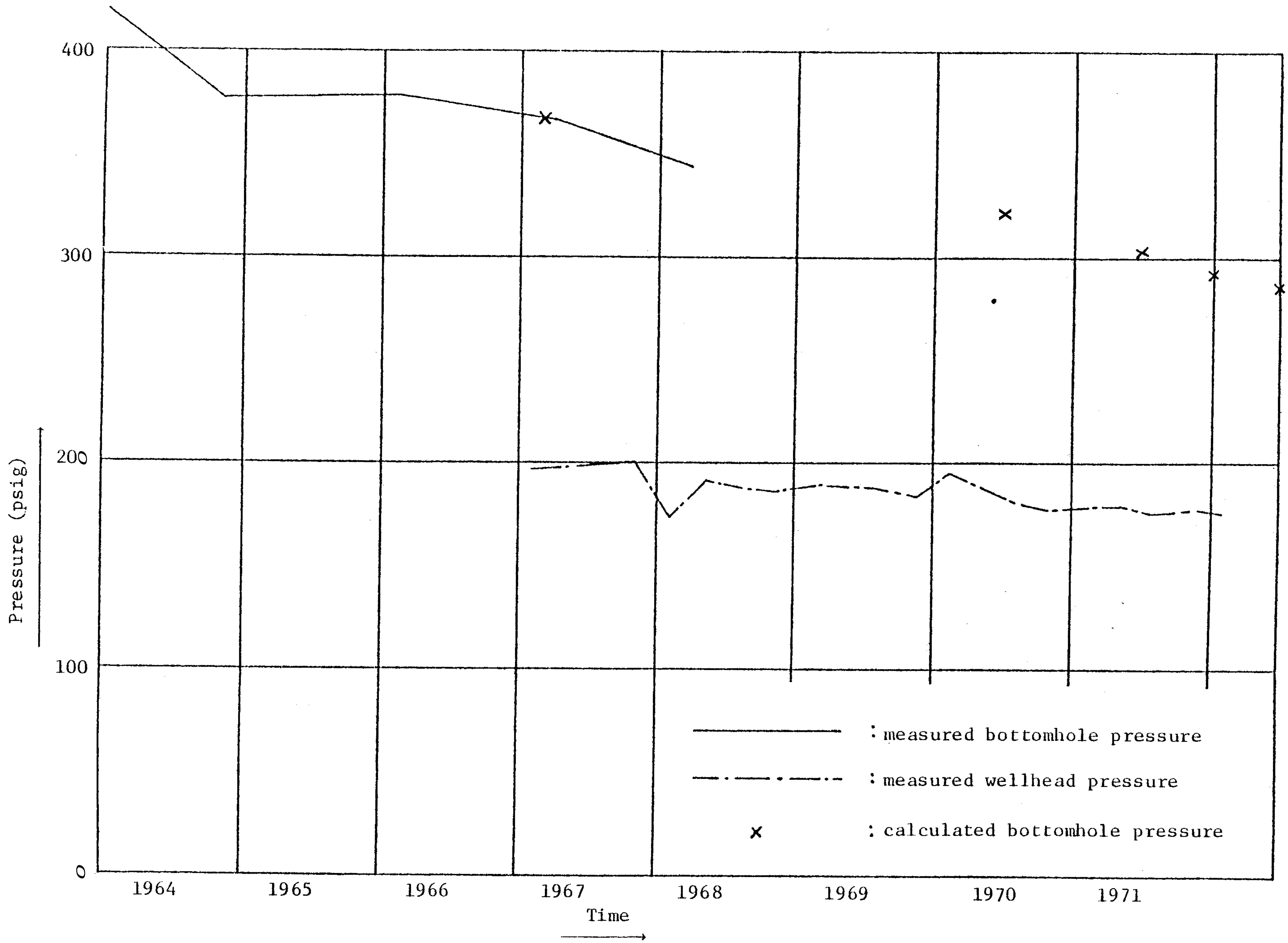

FIG. 19: CALCULATED BOTTOMHOLE PRESSURE FOR WELL 72

diameter down to 1,980 ft, so the estimate of the effective depth is not unrealistic. As Fig. 19 shows, the calculated bottomhole pressures in well 72 agree with the actual values. However, we do not have measured bottomhole pressures after 1968, so we cannot compare exactly.

For the calculation of heat loss from the wellbore, we car, use Ramey's method.[5,6] However, this method is inaccurate for small flow rates. As part of this work, a method to calculate the heat loss from the wellbore for finite flow rates was developed.' By solving the heat balance equations exactly, the following equation was derived:

$$q = aWC\left[H+E(e^{-\frac{H}{E}}-1)\right] \tag{18}$$

where:

$$E = \frac{Wcf(t)}{2\pi k} \tag{19}$$

$$f(t) = -\ln\left(\frac{r_w}{2\sqrt{\alpha_1 - t}}\right) \quad 290 \tag{20}$$

The heat loss from the wellbore can be obtained by this equation, and thus the bottomhole values of enthalpy and thence the steamlwater ratio can be calculated. However, if the well has been produced for a long time and is not too deep, the calculated heat loss from the wellbore becomes small, and the difference between wellhead and bottomhole steam/water ratios is almost negligible. Thus, after an initial check on the magnitude of the heat loss, this additional consideration was not applied to the Wairakei field data used here, since the downhole values of discharge differ from surface values by less than 2%. However, it will probably be necessary to include calculation of the wellbore heat loss in the case of newer wells.

Having calculated pressure drop and heat loss in the wellbore, the bottomhole conditions may be computed from the wellhead conditions by the procedure outlined in Fig. 20. The procedure in this case is summarized below as Method B.

METHOD B

Well Data Required:

- Water Discharge Q_w (at well head)
- Steam Discharge Q_s (at well head)
- Temperature, T (at well head)
- Pressure, p_{BH} (at well head)
- Reservoir Pressure, $\bar{p}$

Well Data Inferred: Viscosities μ_w and μ_s

Procedure:

(1) For each well, obtain bottomhole pressure, p_{BH} using the two-phase pressure drop calculation.

(2) Calculate the wellbore heat loss7 and thus obtain the bottom-hole enthalpy, and thence bottomhole values of Q_w and Q_s.

(3) Plot $(Q_w+Q_s)/(\bar{p}-p_{BH})$ against Q_w/Q_s on normal Cartesian graph paper.

(4) Extrapolate the data to the $Q_w/Q_s=0$ axis to obtain C (Eq. 15).

(5) 'Then evaluate k_w and k_s for each point from Eqs. 16 and 17.

(6) Combine and compare the separate well results.

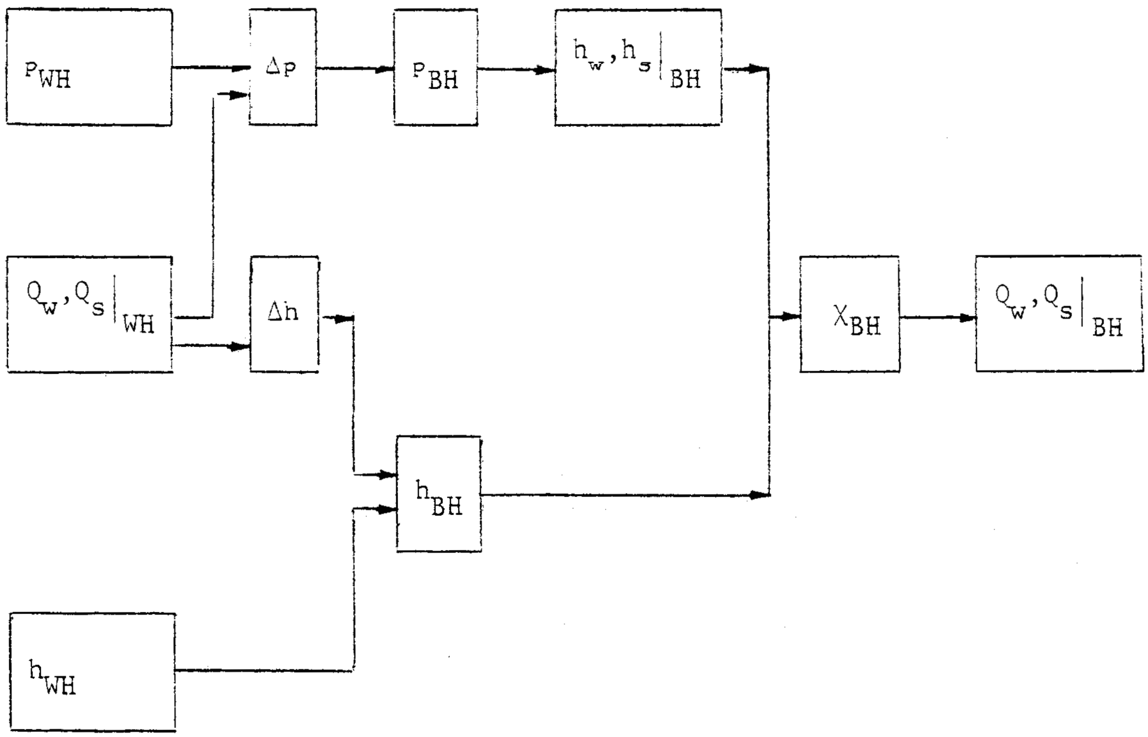

FIG. 20: PROCEDURE TO CALCULATE BOTTOMHOLE CONDITION

However, even though we can now calculate the pressure drop and heat loss in the wellbore more exactly, clearly the best approach would be to obtain those data directly. It would be useful also to check the reliability of the heat and pressure loss calculation methods proposed in this report by using measured values. In such experiments, the parameters that should be measured would be the bottomhole and wellhead pressures, the bottomhole and wellhead temperatures, the production flow rates, and the average reservoir pressure. Simultaneous measurement of these parameters would be necessary.

In summary, when we do not have information other than the production flow rate and the wellhead temperature, we can apply Method A proposed in Section III to obtain relative permeabilities in geothermal reservoirs. If we wish to find more accurate relative permeabilities, the bottomhole conditions can be estimated through the calculation procedure shown in Fig. 20, and these values can be used to obtain more accurate relative permeabilities as shown in Method B. However, the best procedure would be to perform the experiment and obtain bottomhole values, after which the relative permeability curves can be estimated using Method B, starting at Step 3 of the procedure.

V. USE OF RELATIVE PERMEABILITY CURVES

Reliable relative permeability curves for geothermal reservoirs can be used as a basis for the development of new well-test analysis techniques. This approach may be of particular importance if the relative permeability curves are different for each reservoir. In such cases, obtaining the relative permeability curves would be essential to well-test analysis.

Boiling, two-phase flow is generally non-isothermal. However, simplified equations can be written in terms of isothermal flow. From the material balance for an isothermal radial flow system:

$$\frac{1}{r}\frac{\partial}{\partial r}\left[r\left(\frac{\rho_w k_w}{\mu_w}+\frac{\rho_s k_s}{\mu_s}\right)k\,\frac{\partial p}{\partial r}\right]=\frac{\partial}{\partial t}\,(\bar{\rho}\phi) \tag{21}$$

Assuming that **k** and ϕ are constant:

$$\frac{1}{r}\frac{\partial}{\partial r}\left[r\left(\frac{\rho_w k_w}{\mu_w}+\frac{\rho_s k_s}{\mu_s}\right)\frac{\partial p}{\partial r}\right]=\frac{\phi}{k}\frac{\partial\bar{\rho}}{\partial t} \tag{22}$$

Then:

$$\left(\frac{k_w}{\nu_w}+\frac{k_s}{\nu_s}\right)\frac{\partial^2 p}{\partial r^2}+\frac{1}{r}\left(\frac{k_w}{\nu_w}+\frac{k_s}{\nu_s}\right)\frac{\partial p}{\partial r}+\frac{\partial}{\partial e}\left(\frac{k_w}{\nu_w}+\frac{k_s}{\nu_s}\right)\left(\frac{\partial e}{\partial p}\right)\left(\frac{\partial p}{\partial r}\right)^2=\frac{\phi}{k}\frac{\partial\bar{\rho}}{\partial t} \tag{23}$$

$\bar{\rho}$ is given as:

$$\bar{\rho}=\frac{Q_w+Q_s}{V_w+V_s}$$

$$=\frac{\dfrac{k_w}{\nu_w}+\dfrac{k_s}{\nu_s}}{\dfrac{k_w}{\mu_w}+\dfrac{k_s}{\mu_s}} \tag{24}$$

Then :

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r}\frac{\partial p}{\partial r} + \frac{\partial}{\partial e}\left[\ell n\left(\frac{k_w}{\nu_w} + \frac{k_s}{\nu_s}\right)\right]\left(\frac{\partial e}{\partial p}\right)\left(\frac{\partial p}{\partial r}\right)^2$$

$$= \frac{\phi}{k\left(\frac{k_w}{\nu_w} + \frac{k_s}{\nu_s}\right)} \cdot \frac{\partial}{\partial e}\left(\frac{\frac{k_w}{\nu_w} + \frac{k_s}{\nu_s}}{\frac{k_w}{\mu_w} + \frac{k_s}{\mu_s}}\right)\left(\frac{\partial e}{\partial r}\right)\left(\frac{\partial p}{\partial t}\right) \tag{25}$$

If we can assume that the pressure gradient is negligible, then:

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r} \cdot \frac{\partial p}{\partial r} = \frac{\phi}{k\left(\frac{k_w}{\nu_w} + \frac{k_s}{\nu_s}\right)} \cdot \frac{\partial}{\partial e}\left(\frac{\frac{k_w}{\nu_w} + \frac{k_s}{\nu_s}}{\frac{k_w}{\mu_w} + \frac{k_s}{\mu_s}}\right)\left(\frac{\partial e}{\partial p}\right)\left(\frac{\partial p}{\partial t}\right) \tag{26}$$

This equation is similar to the diffusivity equation of the liquid flow case. If we can solve this equation, we can develop useful techniques for well-test analysis of two-phase geothermal systems. In solving this equation, we would use the relative permeabilities obtained using the method proposed in this report. This should be a fruitful area for future research.

VI. CONCLUSIONS

A new method has been developed to calculate steam/water relative permeabilities in geothermal reservoirs. This method has the following characteristics:

(i) We can get the relative permeabilities from the production flow rate history and wellhead temperature alone.

(ii) This method avoids some of the simplifying assumptions which Grant[1] made, and is an improvement on the method of Horne[2] in that the bottomhole characteristics can be explicitly considered.

(iii) This method decreases the scatter of the data by evaluating precisely kAp' values for each well.

Further, the method can be improved greatly if more complete information on the bottomhole conditions of the well is available. In order to obtain bottomhole conditions, we must either calculate the pressure drop and heat loss in the wellbore, or must measure the bottomhole conditions directly in the field. This study indicated how to calculate the pressure drop and heat loss in the wellbore, and has shown which parameters we should measure in the field.

The calculated relative permeability curves may be used as a basis for future well-test analysis of geothermal reservoirs. Thus we have designed an operational test procedure to obtain these curves in future applications. With the limited data available to this study, steam/water relative permeabilities have been obtained successfully. With more complete information, the method developed herein should produce reliable results.

VII. NOMENCLATURE

A = flowing area (L^2)

a = geothermal gradient (degree/L)

B = constant (=kAp')

C = constant $\left(= \frac{2\pi kh}{\ell n(\frac{r_e}{r_w}) - \alpha} \right)$

c = specific heat of fluid $\left(\frac{M \cdot \frac{L^2}{T^2}}{M \cdot degree} \right)$

e = water saturation based on a mass ratio

H = depth of well (L)

h_w = enthalpy of water $\left(\frac{M \cdot \frac{L^2}{T^2}}{M} \right)$

h_s = enthalpy of steam $\left(\frac{M \cdot \frac{L^2}{T^2}}{M} \right)$

Δh = enthalpy loss $\left(\frac{M \cdot \frac{L^2}{T^2}}{M} \right)$

K = thermal conductivity of earth $\left(\frac{M \cdot \frac{L^2}{T^2}}{T \cdot L \cdot degree} \right)$

k = permeability (L^2)

k_w = relative permeability of water

k_s = relative perneability of steam

p' = pressure gradient $\left(\frac{M}{T^2 L^2}\right)$

$\bar{p}$ = average reservoir pressure $\left(\frac{M}{T^2 \cdot L}\right)$

p_{WH} = wellhead pressure $\left(\frac{M}{T^2 \cdot L}\right)$

p_{BH} = bottomhole pressure $\left(\frac{M}{T^2 \cdot L}\right)$

p = pressure drop $\left(\frac{M}{T^2 \cdot L}\right)$

Q_w = mass production flow rate of water $(\frac{M}{T})$

Q_s = mass production flow rate of steam $(\frac{M}{T})$

Q_o = mass production flow rate at pure water point $(\frac{M}{T})$

Q^* = mass production flow rate at pure steam point $(\frac{M}{T})$

q = heat loss $\left(\frac{M \cdot \frac{L^2}{T^2}}{T}\right)$

r_e = external radius of reservoir (L)

r_w = wellbore radius (L)

t = production time (T)

V_w = volumetric production flow rate of water $(\frac{L^3}{T})$

V_s = volumetric production flow rate of steam $(\frac{L^3}{T})$

w = mass production flow rate of fluid $(\frac{M}{T})$

x = wetness of fluid

GREEK NOMENCLATURE

α = constant

α_1 = thermal diffusivity of earth $(\frac{L^2}{T})$

ρ_w = density of water $(\frac{M}{L^3})$

ρ_s = density of steam $(\frac{M}{L^3})$

$\bar{\rho}$ = average density of fluid $(\frac{M}{L^3})$

μ_w = viscosity of water $(\frac{M}{LT^2})$

μ_s = viscosity of steam $(\frac{M}{LT^2})$

ν_w = kinetic viscosity of water $(\frac{L^2}{T})$

ν_s = kinetic viscosity of steam $(\frac{L^2}{T})$

ϕ = porosity

VIII. ACKNOWLEDGEMENT

The encouragement and advice of Dr. R. N. Horne during this research is greatly appreciated.

Financial support for this study was provided by the Nippon Steel Corporation, Japan, by the Department of Energy Grant, LBL Contract No. 167-3500, and by Stanford University.

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