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Title of Thesis — Titre de la thèse
THE ROLE OF INJECTION RATE AND ADSORPTION IN CAUSTIC FLOODING

University — Université
UNIVERSITY OF ALBERTA

Degree for which thesis was presented — Grade pour lequel cette thèse fut présentée
M. Sc.

Year this degree conferred — Année d'obtention de ce grade 1980	Name of Supervisor — Nom du directeur de thèse DR. S.M. FAROUQ ALI

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THE UNIVERSITY OF ALBERTA

THE ROLE OF INJECTION RATE AND ADSORPTION IN CAUSTIC FLOODING

by

ⓒ Robert William Philip SYMONDS

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES AND RESEARCH
IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE DEGREE
OF MASTER OF SCIENCE
IN
PETROLEUM ENGINEERING

DEPARTMENT OF MINERAL ENGINEERING

EDMONTON, ALBERTA
FALL 1980

THE UNIVERSITY OF ALBERTA

FACULTY OF GRADUATE STUDIES AND RESEARCH

The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research, for acceptance, a thesis entitled THE ROLE OF INJECTION RATE AND ADSORPTION IN CAUSTIC FLOODING submitted by Robert William Philip SYMONDS in partial fulfilment of the requirements for the degree of MASTER OF SCIENCE in PETROLEUM ENGINEERING.

....

Supervisor: Dr S.M. Farouq Ali

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Date May 13, 1980

ABSTRACT

A caustic flooding study, using Ottawa sand and native crude oil, was conducted to investigate the effects of linear rate and adsorption on oil recovery. Thirteen runs were conducted, twelve with the sodium hydroxide solutions displacing the Wainwright crude oil and a final displacement of an artificial brine by a 0.1 % by weight sodium hydroxide solution. All displacements were carried out at 23°C.

Three different sodium hydroxide concentrations were used and an improvement in oil recovery, over that obtained for a brine flood, was noted for the 0.01 and 0.1 % by weight displacements but not for the 2.0 % displacement. Oil recovery at two pore volumes injected was superior in the 0.01 % displacement, while the breakthrough recovery was superior in the 0.1 % displacements. Linear rate had differing effects on the 0.01 and 0.1 % displacements.

The oil recovery in the 0.1 % by weight displacements, where the recovery mechanism appeared to be emulsification and entrainment, seemed essentially independent of rate. Only at the extreme rates, 0.03 and 14.49 m/day, was the recovery significantly affected.

The oil recovery in the 0.01 % by weight displacements, where the recovery mechanism was postulated to be emulsification and entrapment, exhibited a maximum of 75.5 % of the initial oil in place at 3.05 m/day.

Consumption of sodium hydroxide by the sandpack was found to be significant.

ACKNOWLEDGEMENTS

The author would like to express his appreciation to Dr. D.L.Flock for the initial motivation for this study. Acknowledgement is gratefully given to Dr. S.M.Farouq Ali for the innumerable consultations during the course of the study.

The author would also like to thank Mr. G.T.Walsh for modifications to the experimental equipment and Hans Nerenberg for his help and suggestions in the laboratory.

Acknowledgement is gratefully given to the Petroleum Aid to Education Fund for financial assistance during this study.

Finally, the author gratefully acknowledges his friends and fellow graduate students for their suggestions and support which facilitated the completion of this study.

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NOMENCLATURE

C	Concentration of solute in fluid phase
C_0	Concentration of solute in incoming fluid
C_s	Concentration of solute in solid phase
D	Longitudinal dispersion coefficient
D^*	Diffusion coefficient
K_1'	Rate constant in equilibrium rate equation
K_2'	Rate constant in equilibrium rate equation
K_1	Rate constant in nonequilibrium rate equation
K_2	Rate constant in nonequilibrium rate equation
K_{ro}	Relative permeability to oil
K_{rw}	Relative permeability to water
L	Length of sand pack
S	Normalized water saturation
S_w	Actual water saturation
S_{wi}	Irreducible water saturation
T	Time to inject 1 pore volume
t	Time
U	Error function arguement
u	Average pore velocity
V	Volume injected at time t
V_p	Pore volume
x	Distance from the inlet of the porous medium
x_1	Distance from the midpoint of the flood front
ϕ	Porosity
λ	Variable of Integration

1. INTRODUCTION

Large quantities of viscous crude oil exist throughout the world: maximizing the recovery from these deposits is of great interest in these days of ever-increasing oil prices. It is well known that conventional water flooding, although increasing the recovery of oil, leaves a substantial residual oil saturation. The possibility of reducing this residual saturation via the use of chemical additives is, as a result, being actively investigated.

Caustic is just one of the many possible additives that has been, and continues to be, studied. Although many variables, such as interfacial tension, are known to affect the recovery process, little theoretical work has been attempted, and no satisfactory mathematical representation of the process exists at this time.

The present study was devoted to the study of the effect of rate on oil recovery in caustic floods, and the adsorption of caustic on the rock surfaces. It is hoped that a better understanding of the adsorption phenomenon could lead to a more complete theoretical framework for caustic flooding.

1.1 Organization of the Thesis

A review of the major works relating to caustic flooding is presented in Chapter 2. The vast quantity of literature on the many aspects of caustic flooding necessitates that this is not a comprehensive review, but rather a review of selected works. The proposed recovery mechanisms are presented, and some of the factors affecting them examined.

Some of the factors effecting caustic flooding are given in the third section of this chapter. The recently reported possibility of time dependence is briefly examined in the fourth section.

The final section of this chapter is devoted to the basic principles of adsorption and dispersion theory as applied to miscible displacements. The evaluation of the various rate and dispersion constants is examined.

The third chapter states the various specific areas that the study investigated.

The materials and experimental technique employed during this study are outlined in the fourth chapter. As the techniques used are routine, they are mentioned only briefly.

Presented in Chapter 5 are the results of the tests. These results are discussed in an attempt to relate them to the currently accepted mechanisms of caustic flooding. The results and conclusions of this study are summarized in Chapter 6.

The final chapter outlines specific recommendations for further study. It is hoped that work in these areas will provide further insight into the mechanisms of caustic flooding.

2. THEORY AND LITERATURE REVIEW

2.1 History of Chemical Water Flooding

The use of chemical additives in flood water was proposed by Atkinson(1927). The benefits of alkaline flood water additives were known even before this as shown by the works of Nutting(1925), Uren and Fahmy(1927) and Bekstrom and Van Tuyl(1927).

Nutting(1925) described the addition of alkali salts, such as sodium carbonate, to the flood water in order to improve waterflood recovery. He dismissed the use of stronger bases, sodium hydroxide for example, on the grounds that they would be excessively reactive with the crude oil and would be used up by the oil before they could be effective. Despite this, Atkinson's patent of 1927 described the benefits of stronger bases including sodium and potassium hydroxide. Bekstrom and Van Tuyl(1927) also reported improved oil recovery with the use of both strong and weak bases. Uren and Fahmy(1927) confirmed the results of Bekstrom and Van Tuyl(1927) and attributed the increase to the release of trapped oil from the rock surface.

Nutting(1925) had found that the alkali prevented the formation of semi-solid, crude-oil-water interfacial films; however, he did not correlate this with increased recovery. Atkinson(1927), on the other hand, recognized that the capillary and adhesive properties of the oil would cause it to be held in the pore structure, and that the addition of an alkali overcame these forces and released the oil. This mechanism was postulated to be a combination of wettability alteration and interfacial tension reduction in agreement with the findings of Bekstrom and Van Tuyl(1927).

Bekstrom and Van Tuyl(1927) also maintained that the formation of emulsions was undesirable. This conflicts with the views of Subkow(1942), who considered emulsification to be the essential first step in the recovery process. He stated that emulsification must be followed by the entrainment of the emulsion in the flowing alkali stream in order to increase oil recovery.

2.2 Proposed Recovery Mechanisms

Johnson(1976) performed a thorough review of the status of caustic flooding methods and classified the proposed mechanisms into the following four types:

1) Emulsification and Entrainment
2) Wettability Reversal (oil-wet to water-wet)
3) Wettability Reversal (water-wet to oil-wet)
4) Emulsification and Entrapment

Each of these mechanisms is reviewed below.

2.2.1 Emulsification and Entrainment

This mechanism was first proposed by Subkow(1942) in relation to the recovery of bitumen. He stated that the formation of an emulsion was the essential first step in the recovery process, followed by the entrainment of this emulsion in the flowing alkali with the mixture subsequently produced. He postulated that the alkali solution caused the formation of emulsification agents which lowered the interfacial tension. These agents were formed from reactions between the sodium hydroxide and the organic acids present in the bitumen. The bitumen was emulsified into an oil-in-water emulsion and stripped from the sand grains. He foresaw the dangers of using high concentrations of alkali on two grounds:

1) Excessive alkali could cause the formation of a water-in-oil emulsion.
2) The high electrolytic concentrations could prevent the formation of the emulsion.

Reisberg and Doscher(1956) studied the effect of pH on the oil-water interface using a Ventura, California, crude oil. They concluded that for the same interfacial tension to oil, a caustic solution would displace the oil, while an acid solution would not. They attributed this to the stability of the rigid films at the interface confirming the earlier work of Nutting(1925). The rigid film was isolated and found to be a highly oxygenated, low molecular weight constituent of the resins and asphaltenes found in the oil. This confirmed the earlier work of Dodd, et al.(1952).

Reisberg and Doscher(1956) felt that the ability of the caustic to prevent adherence of the oil to the rock surfaces was important; however, they placed primary importance on the emulsification and entrainment mechanism. They concluded that caustic flooding was impractical because adsorption on, and reaction with, the rock and displacement of connate water would cause the alkali to fall behind the oil-water interface. As a result, they concluded that an increase in oil recovery would not be evident until several pore volumes of caustic had been injected, an economically prohibitive situation.

Chan(1979), working with Wainwright crude oil, concluded emulsification of the oil to be vital for increased oil recovery. This conclusion was based on the insignificant recovery increase in tests where emulsification did not occur.

2.2.2 Wettability Reversal (Oil-wet to Water-wet)

Wagner and Leach(1958) obtained improved oil recovery through the injection of chemical solutions which reversed rock wettability from oil-wet to water-wet. The chemicals included acids, bases and certain salts. They recognized that the improvement could be attributed to the improved mobility ratio, due to favourable changes in oil and water relative permeabilities, in the region where oil was still flowing. This decrease in mobility ratio could also temporarily halt the gradual increase in producing water-oil ratio.

They reasoned that the injected water would displace the connate water in front of it and, thus, the injected chemical would only contact the residual oil left behind the connate water bank. Since, in a water-wet system, the residual oil is discontinuous they concluded that a water-wet system would not respond to this wettability change.

The acidic solutions were dismissed on the grounds that they are too reactive with most reservoir rocks. Consequently Leach, et al.(1962) performed both laboratory and field tests using sodium hydroxide and obtained improvements in oil recovery in the regions where the wettability change took place. These improvements were similar to those obtained by Wagner and Leach(1958).

Mungan(1966,a) performed laboratory tests similar to those of Leach, et al.(1962), and confirmed the improvement in mobility ratio. He also found that, for his system, the process was temperature dependent. The recovery mechanism worked well at 71.1°C (160°F) but not at 21.1°C (70°F). This temperature dependence was later confirmed by Cooper(1971), and attributed to the temperature sensitivity of interfacial tension. A later paper by Mungan(1966.b) confirmed the benefits of a wettability alteration from oil-wet to water-wet on the recovery of oil from Teflon cores.

Ehrlich, et al.(1974) concluded that wettability reversal was a viable process in light oil reservoirs. They noted, however, that if the interfacial tension was too low, oil recovery would still increase, but the mechanism would be emulsification and entrainment.

Scott, et al.(1965) found a significant increase in oil recovery with the use of weak caustic solutions. They attributed the increase in oil recovery to a shift in wettability toward water-wet. Their core was initially "neutral or slighty oil-wet". The observed shift in the unsteady state relative permeability curve, toward increased oil permeability, was offered, as evidence for the proposed mechanism.

Minssieux(1977) presented similar evidence to support his conclusion that the addition of caustic increased the wettability to water of the reservoir rock surfaces. He did not, however, report the original state of his system.

2.2.3 Wettability Reversal (Water-wet to oil-wet)

Cooke, et al.(1974) reported a third mechanism by which sodium hydroxide could improve oil recovery. They showed that, under certain conditions of pH, salinity and temperature, some systems could be converted from water-wet to oil-wet. With the right crude oil, this reversal would be accompanied by a dramatic reduction in interfacial tension. The low values of interfacial tension are due to the reaction of the alkali with organic acids, at the water-oil interface, forming soaps. The solubility of these soaps, in the aqueous phase, is highly dependent on its salinity. The steps in the process are:

1) Conversion of the rock from water-wet to oil-wet.
2) The previously discontinuous residual oil

saturation becomes continuous, and oil is able to flow.

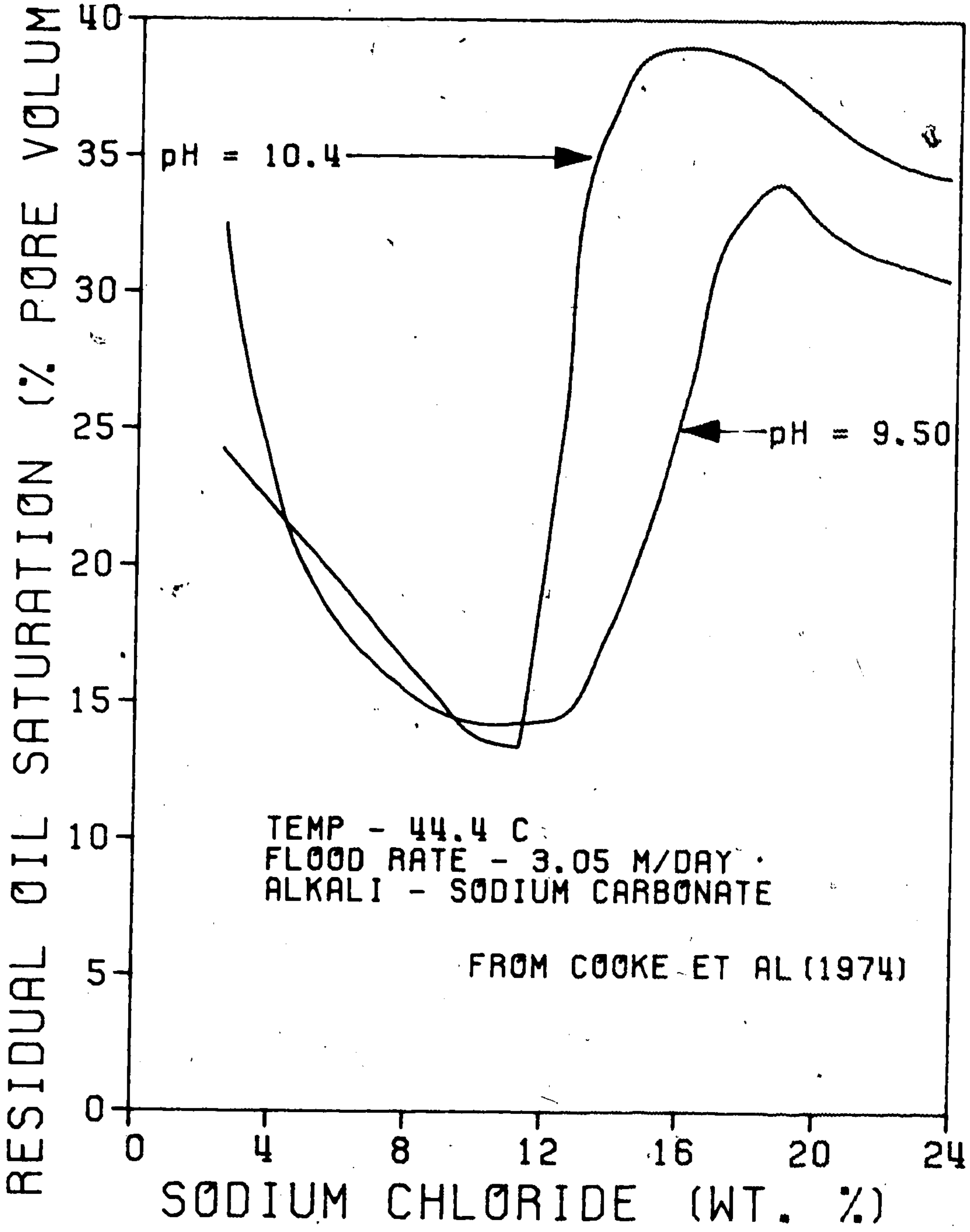
3) The low interfacial tension induces the formation of oil-in-water emulsions.
4) The emulsion droplets block off the smaller pore throats causing large pressure drops in the region.
5) The high pressure gradients overcome the capillary forces, already lessened by the lower interfacial tension. This further reduces the residual oil saturation.

The result is that a high water content emulsion is left behind in the pore structure.

The most distinctive feature of this mechanism is the wettability change. In this regard, as can be seen from Figure 1, the pH and salinity of the aqueous phase appear critical.

The work of Minssieux(1977), however, showed that when salt was present in the caustic solution the interfacial tension was not as low as that obtained in its absence. The Emeraude crude used in part of his study typified this finding; however, the improvements obtained in oil recovery were still attributed to a wettability shift toward oil-wet. This would suggest that only part of the proposed mechanism is required to improve oil recovery.

FIG 1 : EFFECT OF FLOOD WATER SALINITY ON RECOVERY



FROM COOKE ET AL (1974)

2.2.4 Emulsification and Entrapment

This final mechanism was proposed by Jennings, et al.(1974), and is restricted to water-wet systems. In this mechnism the emulsion is not produced as in emulsification and entrainment, rather, it blocks off the smaller pore throats and increases vertical and areal sweep efficiencies. The residual oil saturation is not substantially reduced and, as a result, this mechanism is best suited to viscous oils where sweep efficiency is normally poor.

This mechanisim involves the residual oil being emulsified in situ, due to the low interfacial tension, and being carried by the flowing alkali until the oil droplets are trapped in the pore throats. This results in reduced water mobility that improves both vertical and areal sweep efficiencies. Due to the fact that the emulsified oil droplets are quickly trapped, the residual oil saturation is not reduced.

The two possible reasons the oil droplets are not pushed through the throats are :

1) The interfacial tension is not low enough and/or
2) The pressure gradient is not high enough.

2.3 Factors Effecting Caustic Flooding

Various factors have been reported to effect the caustic flooding process. These include:

1) Crude Oil Composition: It is agreed that the nature of the polar compounds in the oil

determines whether the caustic will aid the recovery process. A good review of the subject has been published by Ehrlich(1974). Minssieux(1977) suggested that the acid index should be greater than about 0.5 mg KOH/g of crude.

2) Water Composition: This is also an important variable as significant amounts of multivalent positive ions, such as calcium, can cause excessive consumption of the caustic.

3) Rock Reactivity: Minssieux(1977) suggested that the mineralogy of the rock does not impose any special limitations, except in the case of large amounts of gypsum. Johnson(1976), on the other hand, states that the rock is important as it accounts for both consumption and adsorption of the caustic, in addition to playing a major role in deciding which recovery mechanism will dominate.

4) Caustic Concentration: It appears that the optimal level of caustic concentration depends upon the prevailing recovery mechanism. Johnson(1976) reports concentrations as low as 0.001 weight percent for emulsification mechanisms and as high as 15 weight percent for wettability reversals.

2.4 Time Dependence of Caustic Flooding

Recent work by Chan(1979) has suggested the possible need of a minimum residence time for the caustic to react. He suggested that the formation of the oil-in-water emulsions was dependent on the time during which the caustic was in contact with the system. He offered no explanation for this.

Minssieux(1977) studied the effect of time on the interfacial tension between caustic solutions and various crude oils. He found, with a Lacq crude (acid index 0.5 mg KOH/g crude), that the interfacial tension increased with time for any particular caustic concentration. An Emeraude crude (Acid index 1.2 mg KOH/g crude) showed the same trend.

Reisberg and Doscher(1956) also studied the effect of time on interfacial tension against deionized water for 5 crude oils and purified benzene. In all cases, they reported a rapid decrease in interfacial tension followed by a gradual reduction toward some equilibrium value.

McCaffery(1975) studied interfacial tension and aging behaviour of 4 crude oils. He found that the interfacial tension between the oils and sodium hydroxide solutions increased with the interface age. The oils he studied included Viking Kinsella Wainwright B, which displayed an interfacial tension minimum at about 0.25 wt. % sodium hydroxide in injection water. This injection water contained a total calcium and magnesium ion content of approximately 12 grams/m³ (12 parts per million). For this system, the interfacial tension increased from about 8×10^{-5} N/m (0.08 dynes/cm) to about 4×10^{-3} N/m (4 dynes/cm) over some 70 minutes. An aqueous phase of limestone equilibrated water, containing some 26 grams/m³ (26 parts per million) calcium and magnesium ions, displayed a similar initial interfacial tension, but increased more rapidly with aging, reaching 1×10^{-2} N/m (10 dynes/cm) after only 20 minutes.

McCaffery(1975) also observed that the aging period increased with the size of the oil droplet used. This was believed to account for the longer duration of a low interfacial tension for the injection water system.

It was found that the sodium hydroxide in the aqueous phase was not noticeably consumed during the aging periods.

2.5 Dispersion and Adsorption

2.5.1 Introduction

Miscible displacement has been the subject of intensive investigation due to its great potential in tertiary oil recovery. Although caustic flooding is not a miscible process, the theory developed for miscible and miscible-type displacements allows the study of the adsorption phenomenon. Adsorption is believed to play a major role in the caustic recovery mechanisms but little theoretical work on the adsorption of caustic on rock surfaces has been performed. A study of a miscible caustic flood, (e.g. caustic displacing brine) should provide much needed insight into the phenomenon.

2.5.2 Dispersion Theory

In any miscible displacement process, the mixing of two fluids is influenced by diffusion and dispersion phenomena. Dispersion is caused by the uneven movement of fluid, or by the concentration gradient between the two fluids. Two types of dispersion may take place in a porous medium; the first is longitudinal, which is in the direction of flow, and the second is transverse, which is perpendicular to the direction of flow. The "diffusion equation" for longitudinal dispersion is well understood and has been solved by several workers, including Brigham, et al.(1961), using appropriate boundary conditions. One of the solutions presented is:

$$\frac{C}{C_0} = \frac{1}{2}\left[1 - \text{erf}\,\frac{x_1}{2\sqrt{Dt}}\right] \qquad (1)$$

where:

x_1 = distance from the midpoint of the flood front, m

C = concentration of solute in the fluid phase, kg/m^3

C_0 = concentration of solute in input, kg/m^3

D = longitudinal dispersion coefficient, m^2/sec

t = time, seconds

As reported by Brigham, et al.(1961), there is a simple relationship between x_1 and the distance from the inlet of the porous medium x, as shown below:

$$x_1 = x - ut = x - (L/T)t \qquad (2)$$

where:

L = length of the porous medium, m

T = time to inject one pore volume, seconds

u = average pore velocity, m/sec

Equation (1) gives the well known "S" shape concentration profile in the porous medium at a given time. Experimentally, concentration data is obtained at a single point, normally the outlet, therefore, some modification of Equation (1) is needed to make it convenient for experimental purposes. Brigham, et al.(1961) have suggested the following:

$$x_1 = L \frac{V_p - V}{V_p} \tag{3}$$

$$t = T \frac{V}{V_p} \tag{4}$$

where:

V_p = total pore volume of sand pack, ml

V = volume of liquid recovered at time of sample, ml

Then the argument of the error function may be rewritten as,

$$\frac{x_1}{2\sqrt{Dt}} = \frac{L[V_p - V]}{2\sqrt{DV_pVT}} = \frac{L}{2\sqrt{DTV_p}} U \tag{5}$$

where:

$$U = \frac{V_p - V}{\sqrt{V}}$$

The error function parameter, U, may be used to predict the growth of the transition zone. A plot of U versus concentration on arithmetic probability paper should result in a straight line.

Brigham, et al.(1961) obtained the following relationship between the dispersion coefficient, D, and the error function parameter U:

$$D = \frac{1}{V_p T} \left[\frac{U_{90} - U_{10}}{3.625} \right]^2 \qquad (6)$$

where:

U_{90} = Value of U at $C/C_0 = 0.9$

U_{10} = Value of U at $C/C_0 = 0.1$

Equation (6) allows evaluation of D from experimental data.

Raimondi, et al.(1959) presented the following relationship between the longitudinal dispersion coefficient D, and the mixing coefficient α:

$$D = D^* + \alpha u \qquad (7)$$

The mixing coefficient, α is dependent upon core lithology and is independent of fluid properties. At high flow rates, the parameter D^*, the diffusion coefficient, may be neglected. Kasraie(1979) found that the mixing coefficient was rate sensitive with a maximum occurring.

2.5.3 Simultaneous Dispersion and Adsorption

Banks and Ali(1964) modified the dispersion equation to include the adsorption phenomenon. The resulting mass balance on an incremental volume yields:

$$\frac{\partial C}{\partial t} + \frac{1-\phi}{\phi}\frac{\partial C_s}{\partial t} + u\frac{\partial C}{\partial x} = D\frac{\partial^2 C}{\partial x^2} \tag{8}$$

The general form of the rate equation expressing solute transfer between the solid and fluid phases is:

$$\frac{\partial C_s}{\partial t} = f(C,C_s) \tag{9}$$

Once the precise form of the rate equation is specified, equations (8) and (9) may be solved for specified initial and boundary conditions.

Rate equations commonly used in this solution are:

$$\frac{\partial C_s}{\partial t} = K_1C - K_2C_s \tag{10}$$

and

$$C_s = K_1'C + K'_2 \tag{11}$$

where K'_1, K_2', K_1 and K_2 are rate constants. Equation (11) indicates the condition of local equilibrium between the fluid and solid phases at all points in the porous medium. This is a special case of Equation (10) which is the nonequilibrium relationship. Carslaw and Jaeger (1959) solved the equilibrium case for the following boundary and initial conditions:

$$C(x, 0) = 0 \tag{12}$$

$$C_s(x, 0) = 0 \tag{13}$$

$$C(0, t) = C_0 \tag{14}$$

The solution of Equation (7) with Equations (11), (12), (13) and (14) is:

$$\frac{C}{C_0} = \Phi(\xi, \eta) \tag{15}$$

where:

$$\Phi(\xi, \eta) = \frac{1}{2}\left[\operatorname{erfc}\left(\frac{1 - \xi}{2\sqrt{\xi\eta}}\right) + \exp\left(\frac{1}{\eta}\right)\operatorname{erfc}\left(\frac{1 + \xi}{2\sqrt{\xi\eta}}\right)\right] \tag{16}$$

and

$$\xi = \frac{ut}{\theta x} \tag{17}$$

$$\eta = \frac{D}{ux} \tag{18}$$

$$\theta = 1 + \frac{1 - \phi}{\phi} K_1' \tag{19}$$

The general solution of the nonequilibrium case is obtained from Equations (8), (10), (12), (13) and (14). For this case Lapidus and Amundson(1952) obtained:

$$\frac{C}{C_0} = \exp\left[\frac{ux}{2D}\right]\left[G(t) + K_2 \int_0^t G(t)\, dt\right] \tag{20}$$

in which

$$G(t) = e^{-K_2 t} \int_0^t I_0\left\{2\sqrt{\frac{1-\phi}{\phi} K_1 K_2 (t-\lambda)}\right\} \frac{x}{2\sqrt{\pi D \lambda^3}}\, e^{-\frac{x^2}{4D\lambda} - \varepsilon\lambda}\, d\lambda \tag{21}$$

where

$$\varepsilon = \frac{u^2}{4D} + \frac{1-\phi}{\phi} K_1 - K_2 \tag{22}$$

and I_0 is the modified Bessel function of the first kind.

Banks and Ali(1964) presented two special cases of this general solution. The first assumes $K_1 \neq 0$, $K_2 = 0$ and $D \neq 0$. With these assumptions, the solution reduces to the form:

$$\frac{C}{C_0} = \frac{1}{2}\left[\exp\left(\frac{1-\sigma}{2\eta}\right) \operatorname{erfc}\left(\frac{1-\sigma\xi_0}{2\sqrt{\xi_0 \eta}}\right) + \exp\left(\frac{1+\sigma}{2\eta}\right) \operatorname{erfc}\left(\frac{1+\sigma\xi_0}{2\sqrt{\xi_0 \eta}}\right)\right] \tag{23}$$

in which

$$\xi_0 = \frac{ut}{x} \tag{24}$$

$$\eta = \frac{D}{ux} \tag{25}$$

and

$$\sigma = \left[1 + \frac{1-\phi}{\phi} \frac{4DK_1}{\text{[illegible]}2} \right]^{\frac{1}{2}} \tag{26}$$

The second case assumes $K_1 \neq 0$, $K_2 \neq 0$ and $D = 0$. In this instance, with adsorption but no dispersion, Banks and Ali(1964) report the result to be:

$$\frac{C}{C_0} = J(\omega,\ \psi) \tag{27}$$

in which

$$J(\omega,\ \psi) = 1 - e^{-\psi} \int_0^{\omega} e^{-\lambda}\, I_0 \left\{ 2\sqrt{\lambda\psi} \right\} d\lambda \tag{28}$$

and

$$\omega = \frac{1-\phi}{\phi} \frac{K_1 x}{u} \tag{29}$$

$$\psi = K_2 \frac{x}{u} (\xi_0 - 1) \tag{30}$$

2.5.4 Application to Experimental Results

The results presented in the previous two sections provide a theoretical framework within which to examine experimental data. The major difficulties in attempting to match the theory to the results lie in the evaluation of the rate constants and dispersion coefficient. Assigning values to these quantities involves the use of history matching techniques, and consequently invokes the assumptions embedded in the theories. That is, it is required to assume the validity of the theory prior to any attempt to match it with experimental data.

2.5.4.1 Evaluation of the Dispersion Coefficient

The dispersion coefficient, D, may be easily obtained using the procedure of Brigham, et al.(1961), outlined in Section 2.5.2. An experimental system where adsorption is not present must be used, as the theory upon which their method is based is for dispersion only. Since the dispersion coefficient is dependent solely on core properties, a value obtained from a simple dispersion system may subsequently be used in a dispersion and adsorption system. The same flow rate must be used in both experiments since Equation (7) shows that the relative effects of diffusion and dispersion are velocity dependent.

2.5.4.2 Evaluation of the Rate Constants for the Nonequilibrium Case

The values of the nonequilbrium rate constants, K_1 and K_2, may both be evaluated from the experimental data via the second special case of Banks and Ali(1964), presented in Section 2.5.3. The assumption for this case, that D = 0, does not affect the constant evaluation, as might first be suspected. In the absence of adsorption, it is clear that, with or without dispersion, the concentration distribution curve must pass through the point $C/C_0 = 0.5$, $\xi_0 = 1.0$. Therefore any delay in reaching this point is due entirely to adsorption effects.

K_1 may be evaluated by point matching at $\xi_0 = 1.0$; from Equations (27) and (30) we obtain:

$$\left.\frac{C}{C_0}\right|_{\xi_0=1} = J(\omega, 0) \tag{31}$$

In this special case, the J-function reduces to a simple exponential, and Equation (31) becomes:

$$\left.\frac{C}{C_0}\right|_{\xi_0=1} = e^{-\omega} \tag{32}$$

Thus, K_1 is simply evaluated from the above equation. Having evaluated K_1, K_2 may be evaluated by point matching at $C/C_0 = 0.5$. This may be done either graphically (e.g. from Figure 2 from Banks and Ali(1964)) or numerically.

3. STATEMENT OF THE PROBLEM

The objective of this study was to examine the effect of rate on caustic displacements in an unconsolidated porous medium. Specifically, it was desired to investigate:

1. The recovery of Wainwright crude oil as a function of injection rate for a continuous sodium hydroxide displacement.
2. The sensitivity of the rate dependence to the concentration of sodium hydroxide in the displacing fluid.
3. The adsorption phenomenon, both experimentally and theoretically.

4. EXPERIMENTAL EQUIPMENT, MATERIALS AND PROCEDURE

4.1 Experimental Equipment

The core flooding apparatus is shown in Figure 2. The displacement pump was a constant injection rate Ruska pump with mercury as the displacing fluid. All lines connecting the pumps with the stainless steel cylinders were 3.175×10^{-3} metre (1/8 inch) stainless steel tubing. All lines upstream of the cylinders were 6.35×10^{-3} metre (1/4 inch) stainless steel tubing.

The cylinders had capacities of approximately 3.6×10^{-3} cubic metres (3.6 litres) and were fitted with pressure rupture discs at the upstream end. The system was designed for a maximum pressure of 13.1 MPa (1900 psi).

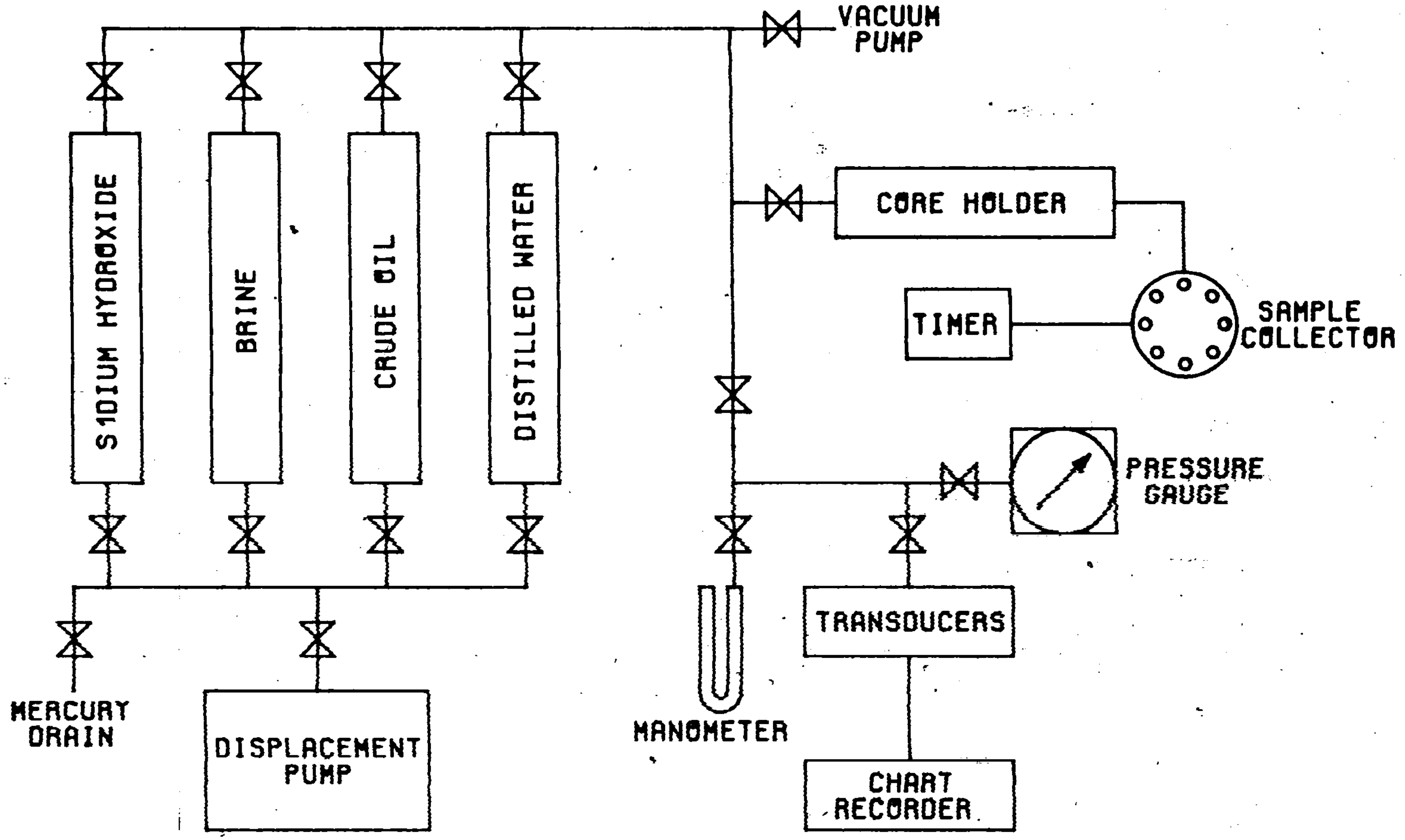
A mercury manometer and a Heise pressure gauge were used to measure the pressure drop across the core pack. Pressure transducers connected to a chart recorder were also used to provide a pressure history for each run.

4.2 Porous Media

4.2.1 Sand

Unconsolidated sandpacks were used throughout this study. The sandpacks were an Ottawa silica sand with a reported grain size range of 80-120 mesh (Fisher Scientific S-151). The sand was used as received from the supplier.

FIG 2 : SCHEMATIC OF CORE FLOODING APPARATUS



4.2.2 Coreholders

The sandpacks were housed in stainless steel coreholders of 5.04 cm nominal diameter. The lengths were all in the range of one metre.

4.2.3 Packing Procedure

A wet packing procedure was used in an attempt to produce similar core properties from run to run. This procedure involved the following steps:

1) The steel coreholder was placed in a vertical position with the downstream endcap in place.
2) Approximately seven centimetres of distilled water were placed in the coreholder. Sand and water were alternately added in an attempt to insure the sand always fell through the same head of water.
3) During the filling process the coreholder was vibrated by an air vibrator.
4) Addition continued until the coreholder was full. The system was then vibrated overnight.
5) Finally the upstream endcap was screwed in place.

The core was then ready for use.

4.3 Fluids

The following fluids were used throughout the experiments:

4.3.1 Brine

An artificial brine was prepared using 88.84 kg/m³ of reagent grade sodium chloride dissolved in distilled water. This was the same brine as used by Gardiner(1977), Scott(1965) and Scott(1971). This brine was used as both connate water and as the displacing fluid for the brine flood.

4.3.2 Caustic Solution

In light of previous work done in the area of optimum caustic concentration, 0.1 % by weight sodium hydroxide in brine was used for the initial runs. This concentration was judged to be optimal by Flock, et al.(1977) and Farouq Ali, et al.(1979). For Runs 8,10,11 and 12 the caustic concentration was reduced to 0.01 % by weight sodium hydroxide in brine, and for Run 9 was increased to 2.0 % by weight. These runs were performed in order to invesigate the sensitivity of recovery to caustic concentration. The caustic solutions were made up from reagent grade sodium hydroxide and the brine solution described above.

4.3.3 Oil

The oil used in this study was from the Wainwright B

Pool. Excess water was removed from the received sample by the use of a rotary dryer.

4.4 Fluid Properties

4.4.1 Surface and Interfacial Tensions

The interfacial tensions between the crude oil and the various concentrations of sodium hydroxide in brine were obtained using the spinning drop apparatus.The densities required for the calculation of the interfacial tensions were measured with a density meter.

The surface tensions were obtained with a du Nouy tensiometer. These measurements were performed at 23°C.

4.4.2 Viscosities

The viscosities of the various fluids were obtained by the use of Canon-Fenske viscometers. The determinations were made at 23°C.

Appendix A details the properties of the various fluids.

4.5 Sandpack Property Determination

Prior to saturation of the sandpacks with oil, various physical properties were measured. These measurements were performed by routine methods and consequently are only briefly described below.

4.5.1 Porosity

The porosity of the pack was determined via a material balance approach using the displacement of distilled water by brine.

Once the pack was fully saturated with distilled water, the water was displaced horizontally, at a constant rate, by brine, and the chloride content of the effluent monitored by refractive index. Once the chloride content of the effluent reached that of the displacing fluid, the displacement was stopped. A plot, such as Figure 3, was constructed and the area above the curve, obtained with a planimeter, yielded the displaced volume. The pore volume was then evaluated by subtraction of the endcap volumes.

4.5.2 Permeability

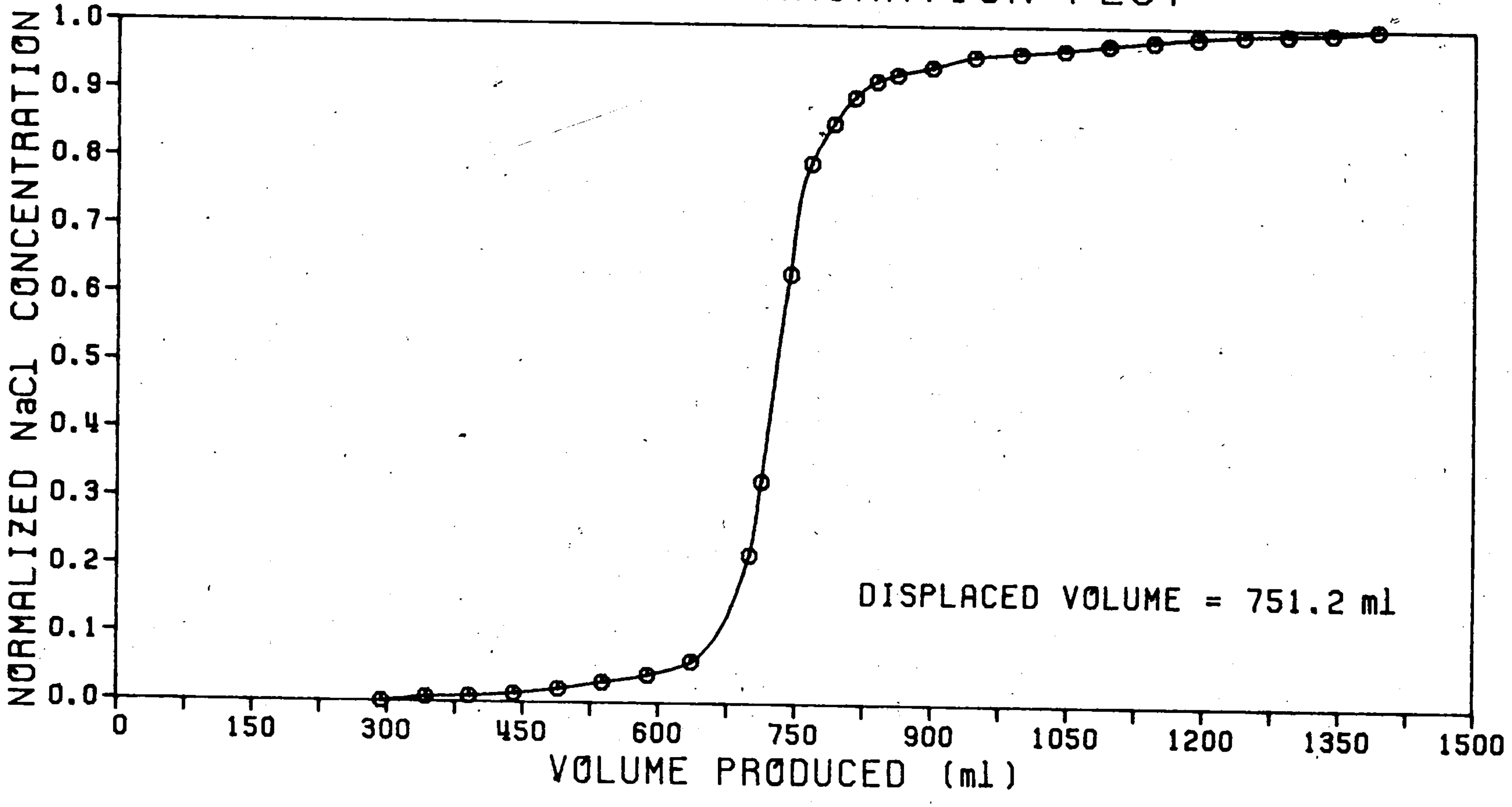
The absolute permeability was obtained by flowing distilled water through the horizontal pack at various rates and utilizing Darcy's Linear Flow Equation.

The physical properties of the cores are provided in Appendix B.

4.5.3 Fluid Saturations

Once the sandpack had been saturated with the brine solution it was suspended vertically. Crude oil was then injected down through the pack and the effluent collected. When the effluent contained less than 1% water the pack was

FIG 3 : TYPICAL POROSITY DETERMINATION PLOT



assumed to be at the irreducible water saturation. The fluid saturations were then calculated via material balance.

4.6 Displacement Procedure

The displacement tests were run at flow rates from 6.94×10^{-9} m^3/sec to 3.33×10^{-6} m^3/sec (2.5 to 1200 cc/hour), which correspond to apparent linear rates of between 0.003 m/day and 14.4 m/day (0.01 to 47.6 feet/day). The produced effluent was collected in 50 ml centrifuge tubes by an indexing sample collector. Where required, the water and oil phases were separated by the addition of toluene and subsequent centrifuging. The pH of the aqueous phase was determined by a digital pH meter. Table 1 summarizes the initial conditions of the cores prior to the commencement of the runs. Table 2 provides a summary of the conditions under which the runs were performed.

In an attempt to reduce the effect of gravity in the very slow floods, Runs 4,6 and 11 were performed vertically. The criterion that only rates less than 0.3 m/day need be done vertically was arbitrary.

A brine flood (Run 1) was performed as a standard for the sodium hydroxide floods. This run was done at an apparent linear velocity of 0.48 m/day and the complete results are presented in Appendix C.

Run 3 involved the use of a "soak period" of 100 hours. This was done by first injecting 0.25 pore volumes of 0.1 % by weight sodium hydroxide in brine. The core was then

Table 1

Initial Conditions of Cores

Run #	Core #	Displacing Fluid	Initial Water in Place (ml)	(%pv)	Initial Oil in Place (ml)	(%pv)
1	3	Brine	63.2	8.3	698.5	91.7
2	3	Caustic	64.7	8.5	697.0	91.5
3	2	Caustic	108.1	15.4	593.6	84.6
4	1	Caustic	115.0	14.6	675.0	85.4
5	4	Caustic	94.0	13.0	630.0	87.0
6	3	Caustic	117.9	14.5	693.0	85.5
7	2	Caustic	76.9	11.1	618.6	88.9
8	4	Caustic	72.9	10.1	649.7	89.9
9	3	Caustic	94.5	11.7	715.4	88.3
10	1	Caustic	81.3	11.3	637.1	88.7
11	4	Caustic	74.1	10.5	632.4	89.5
12	2	Caustic	91.7	12.4	650.5	87.6

Table 2

Run Summary

Run #	Volumetric Flow Rate (cc/hour)	Volumetric Flow Rate (m^3/sec)	Apparent Linear Rate (m/day)	Apparent Linear Rate (feet/day)	Injected Caustic Concentration (Wt %)
1	40.0	1.1×10^{-7}	0.48	1.58	0.00
2	40.0	1.1×10^{-7}	0.48	1.58	0.10
* 3	40.0	1.1×10^{-7}	0.48	1.58	0.10
# 4	2.5	6.9×10^{-9}	0.03	0.10	0.10
5	1200.0	3.3×10^{-6}	14.49	47.55	0.10
# 6	12.5	3.5×10^{-8}	0.15	0.49	0.10
7	250.0	6.9×10^{-7}	3.01	9.87	0.10
8	250.0	6.9×10^{-7}	3.02	9.91	0.01
9	250.0	6.9×10^{-7}	3.01	9.87	2.00
10	40.0	1.1×10^{-7}	0.48	1.58	0.01
# 11	12.5	3.5×10^{-8}	0.15	0.49	0.01
12	1200.0	3.3×10^{-6}	14.49	47.55	0.01
+ 13	1200.0	3.3×10^{-6}	14.49	47.55	0.10

* This run involved a soak period.
# These floods were performed vertically upwards.
\+ This was the caustic displacement of brine.

sealed and allowed to soak for 100 hours without rotation. After this period the displacement was restarted and continued until 2 pore volumes had been injected.

Run 13 was designed to study the adsorption phenomenon, and involved the displacement of brine by 0.1 % by weight sodium hydroxide in brine. The core was prepared in the normal way and the displacement of brine was carried out at 3.3×10^{-6} m^3/sec (1200 cc/hour).

5. DISCUSSION OF RESULTS

The experimental part of this study involved thirteen runs. The theoretical work involved the determination of the adsorption kinetics parameters, and a predicted concentration profile. Run 1 was a brine flood for use as as a reference run for the caustic tests. Runs 2 to 7 involved 0.1 % by weight caustic displacing the Wainwright crude at various different linear rates. Runs 8, and 10 to 12 were performed with 0.01 % by weight sodium hydroxide in brine. Run 13 was a simple displacement of brine by 0.1 % by weight sodium hydroxide in brine, with a view to testing the adsorption theory.

5.1 Sandpack Properties

The wet packing procedure employed during this study, discussed in Section 4.2.3, was expected to provide reproducibility in sandpack properties such as, porosity and absolute permeability. The average porosity obtained was 34.6 % with a standard deviation of 1.2 %. The average absolute permeability was 19.3 darcys with a standard deviation of 1.7. A summary of the physical properties of the individual sandpacks is provided in Table B-1.

The undesireably large variations observed in the physical properties reflect the need for standardizing the packing procedure. More important, one should insure that all packs are made, not only with the same grade of sand but, from the same manufacturers' lot number. This point is emphasized by the fact that the sandpacks for Runs 4 and 6, which yielded high values of porosity and permeability, employed sand from a different lot than the one used for most of the other runs. The sandpack for Run 13, which yielded a below average permeability was from a third lot.

5.2 Initial Fluid Saturations

The initial saturations of the sandpacks are detailed in Table 1 in the previous chapter. The average initial water saturation obtained in the sandpacks for Runs 1 to 12 was 11.8 % with a standard deviation of 2.2 %.

The variation in the initial water saturation was greater than expected, and is again partly attributed to the variations in the sand in the different lots. The sandpacks for Runs 4 and 6, for example, had initial water saturations of 14.6 % and 14.5 %, respectively, 2.8 % and 2.7 % greater than the average. The sandpack for Run 3, however, exhibited another high value despite the fact that the porosity and permeability were close to the average values.

In all, however, the fluid saturations are acceptable for quantitative comparison of the runs. The normalizing of the water saturation in the relative permeability ratio calculations is an attempt to further reduce the effect of these variations.

5.3 Interfacial Tension

The interfacial tension data between various sodium hydroxide solutions and the Wainwright crude are shown in Figure 4. It is evident from Figure 4 that there is no well defined minimum in interfacial tension in the range of caustic concentrations studied.

The interfacial tension is, however, reduced by the addition of sodium hydroxide. There is a low value of interfacial tension at 0.1 % by weight and this was taken as sufficient evidence to use this concentration for the initial tests.

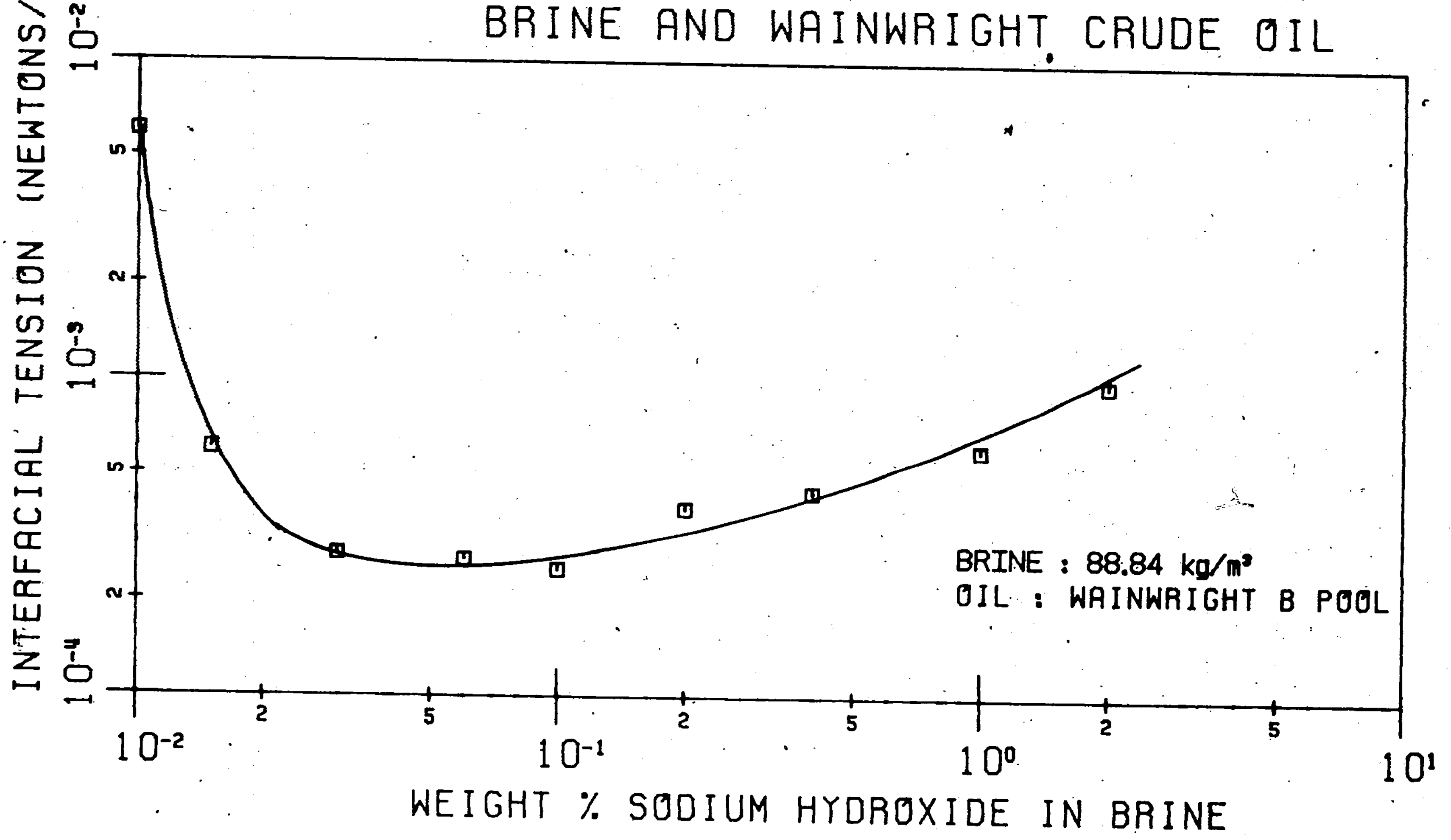
This finding is in conflict with the work of Chan(1979), who found a distinct minimum in the interfacial tension at 0.1 % by weight. Although Chan(1979) used the Wainwright crude, it should be noted that the viscosity was markedly different, 800 mPa.s versus 408 mPa.s. He also employed formation water, while this study employed an artificial brine.

5.4 Displacement Tests

A summary of the displacement tests has been given as Table 2 in Chapter 4. For the purpose of initial discussion the displacement tests have been divided into five sections:

1) Run 1: A brine flood to be used as a base run for comparing the caustic floods.
2) Runs 2 - 7: These runs were performed using 0.1 % by weight sodium hydroxide in brine, in

FIG 4 : INTERFACIAL TENSION BETWEEN A BRINE AND WAINWRIGHT CRUDE OIL



order to investigate the effect of rate on oil recovery. Run 3 also studied the effect of a soak period.

3) Runs 8, 10 - 12: These runs investigated the rate effect for a different caustic concentration, 0.01 % by weight sodium hydroxide in brine.

4) Run 9: This run was for a sodium hydroxide concentration of 2.0 % by weight. This allowed comparison of the oil recovery at a particular rate for 3 different caustic concentrations.

5) Run 13: This run involved the displacement of brine by 0.1 % by weight sodium hydroxide in brine, to obtain an experimental caustic concentration profile in the effluent for comparison with that predicted [illegible] the theory.

5.4.1 Brine Flood

Run 1 involved the flooding of a core with an artificial brine containing 88.84 kg/m^3 sodium chloride. The production history for this run is provided as Table C-1 and Figure C-1 in Appendix C. This test was performed at an apparent linear rate of 0.48 m/day. The recovery at 2 pore volumes injected was 53.9 % of the initial oil in place.

The behaviour of the flood was as classically expected, and the plot of relative permeability ratio versus a normalized water saturation produced the expected straight line relationship. This graph is presented as Figure C-3 in Appendix C.

The calculation of the relative permeability ratio was performed using the Welge integration of the Buckley-Leverett equation from displacement data, as given by Collins(1961). The decision to use a normalized water saturation rather than the actual saturation, as suggested by Collins(1961), was based on the desire to quantitatively compare the relative permeability ratio, from the various tests, on a consistent basis. Due to the lack of knowledge of the residual oil saturation, the following definition of normalized saturation was used:

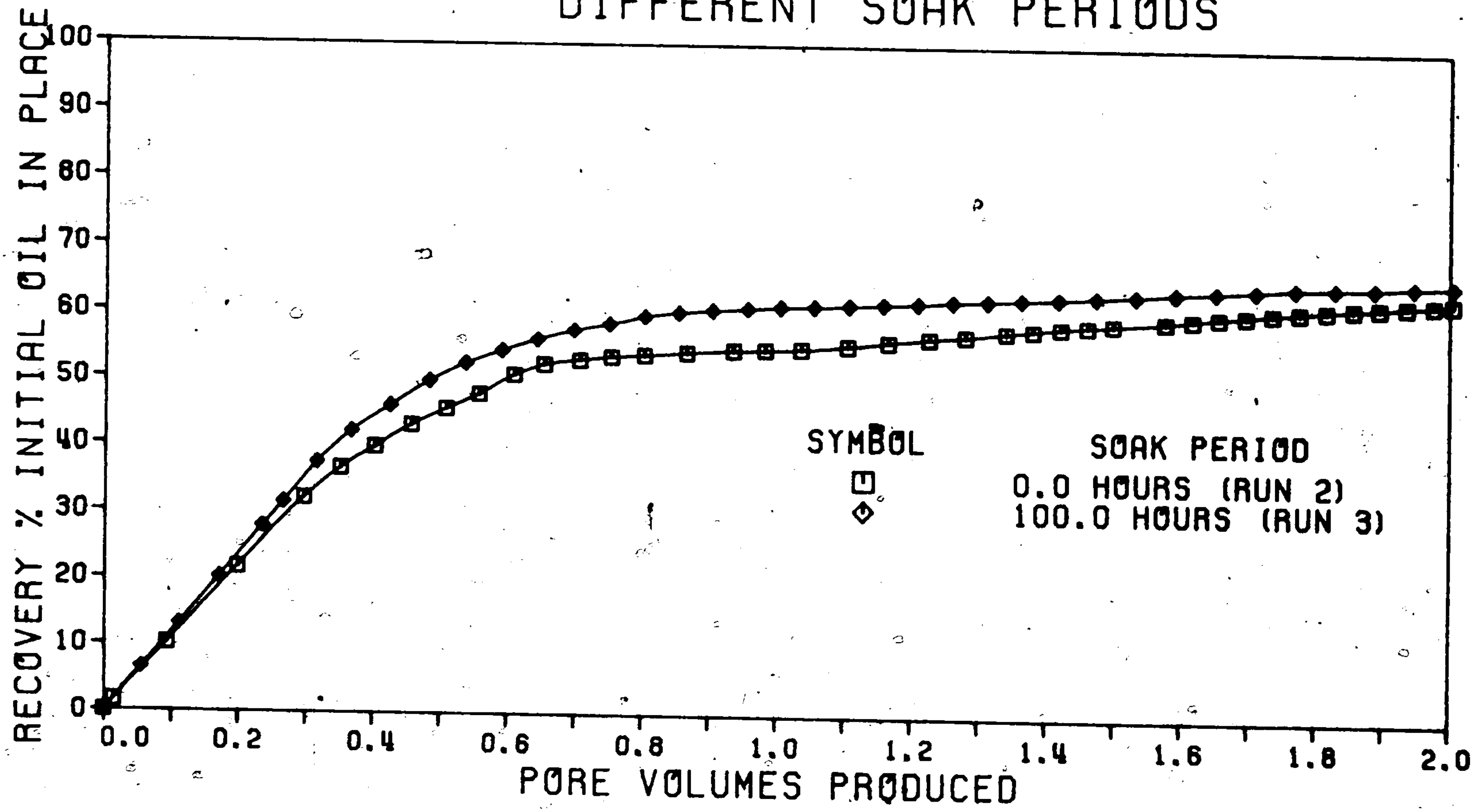
$$S = \frac{S_w - S_{wi}}{1 - S_{wi}} \qquad (33)$$

5.4.2 Tests with 0.1 % by Weight Sodium Hydroxide

The initial caustic floods were performed using 0.1 % by weight sodium hydroxide in brine as the displacing fluid. Runs 2 and 3 were performed at the same linear rate (0.48 m/day) and differed only in that Run 3 utilized a "soak period".

Run 3 was performed to examine whether the "real time" concept proposed by Chan(1979) plays a role in the system under study. It is apparent from Figure 5 that the recovery histories for the two runs were essentially the same. Chan(1979) found that the recovery improved dramatically,

FIG 5 : RECOVERY CURVES FOR DIFFERENT SOAK PERIODS



once the contact time exceeded some minimum. As this did not appear to be the case for the system under study the concept of a time dependence was not studied further.

The remaining 0.1 % by weight floods, Runs 4 to 7, studied the effect of rate on oil recovery at both breakthrough, and two pore volumes injected. The complete series of production histories is shown on Figure 6. The individual run histories are provided in both tabular and graphical form in Appendix 9. Figure 6 demonstrates the apparent insensitivity of the recovery process to rate. All the tests, with the exception of Run 5, follow an almost identical path. The breakthrough in Run 5, performed at 14.49 m/day (47.55 ft/day), was earlier than in the other runs, but the recovery at 2 pore volumes injected is difficult to distinguish from the other runs.

This data is more elegantly displayed in Figure 7 from which it may be clearly seen that there is little significant difference in oil recovery except at the extremes of linear velocity.

This would suggest that the dominant recovery mechanism is largely insensitive to rate. This will be discussed further in Section 5.5 .

5.4.3 Tests with 0.01 % by Weight Sodium Hydroxide

These floods were undertaken to invesigate the sensitivity of the dominant displacement mechanism to caustic concentration. Also, by performing a series of tests

FIG 6 : RECOVERY CURVES FOR DIFFERENT LINEAR RATES

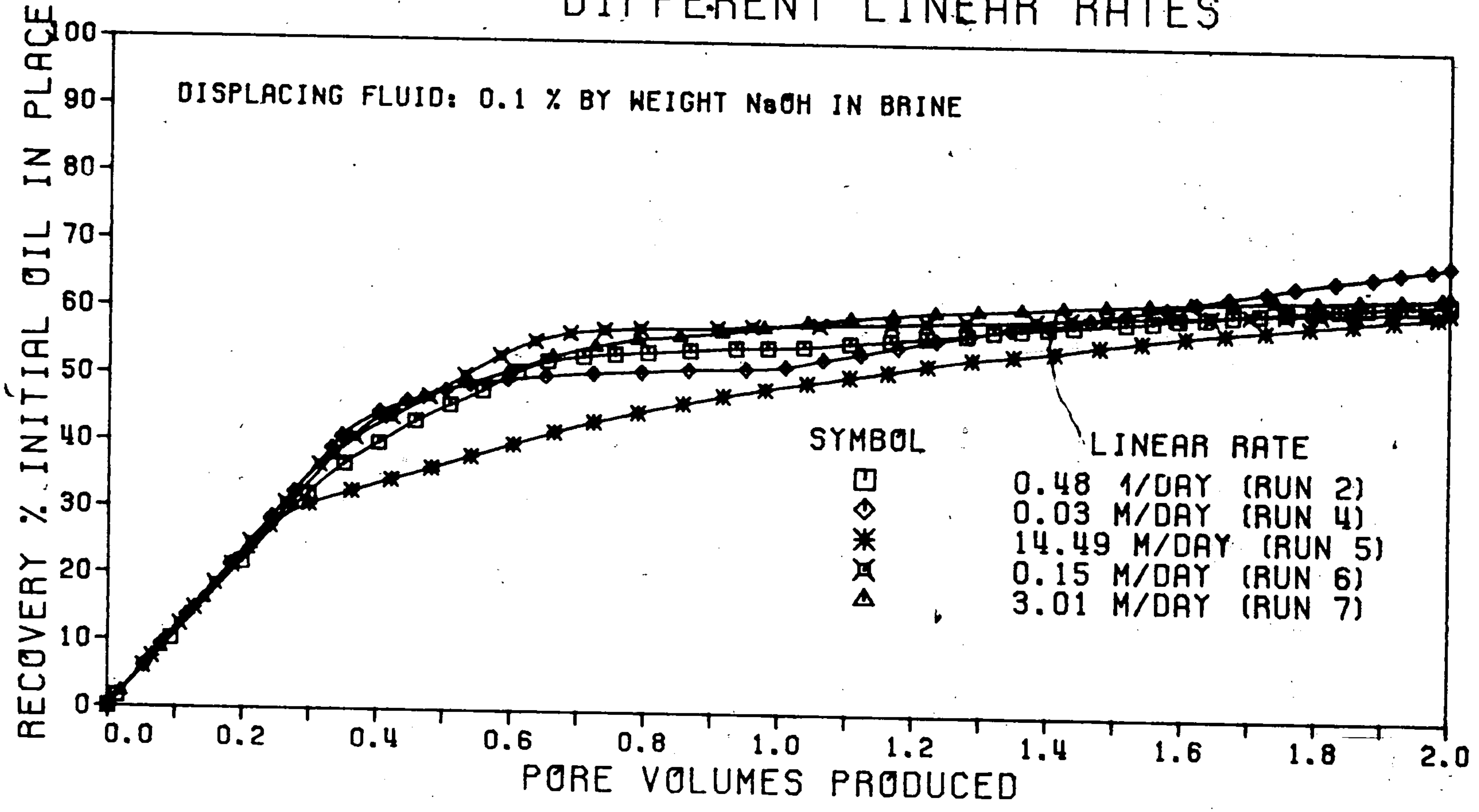
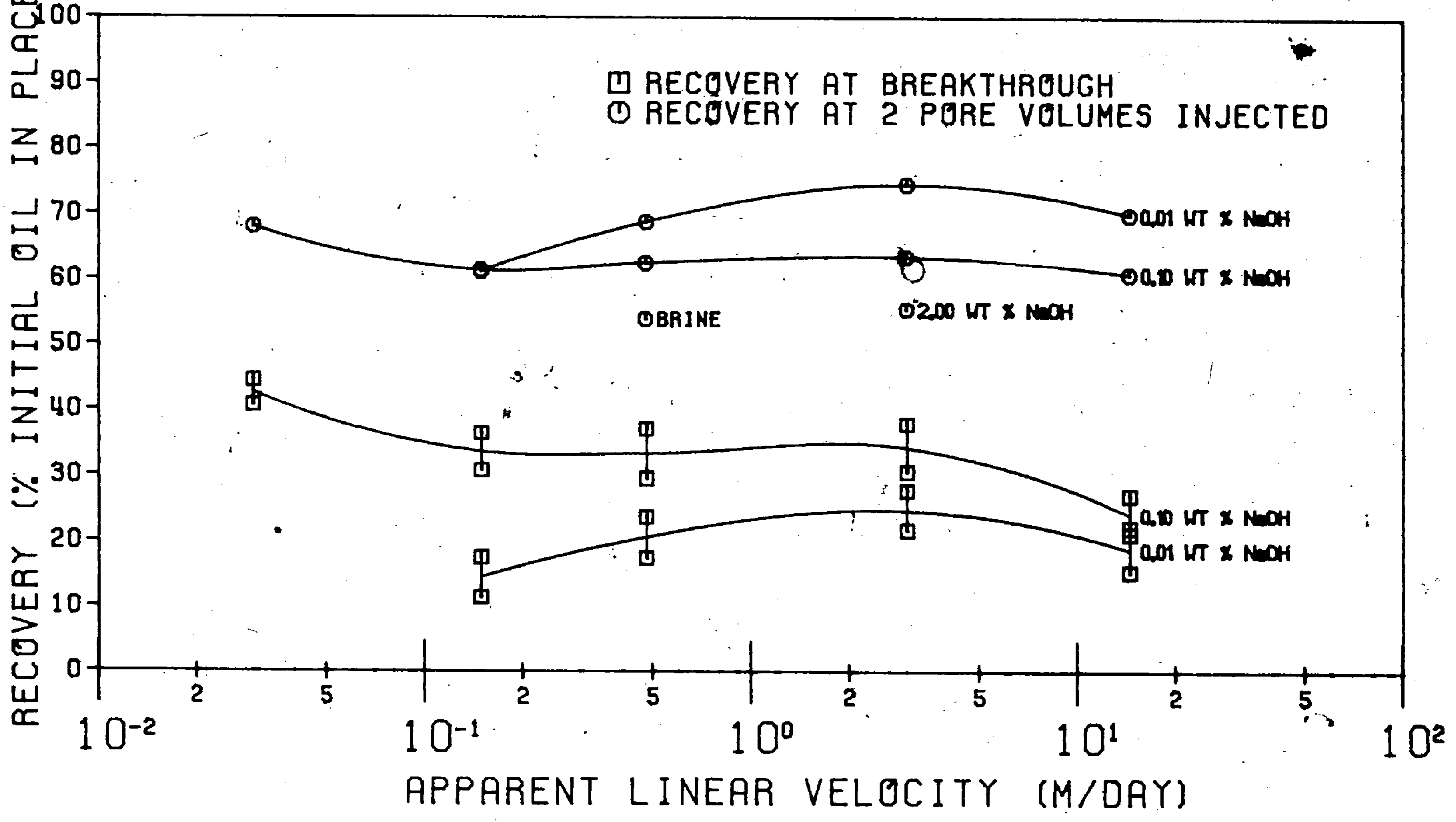


FIG 7 : RECOVERY AS A FUNCTION OF LINEAR VELOCITY



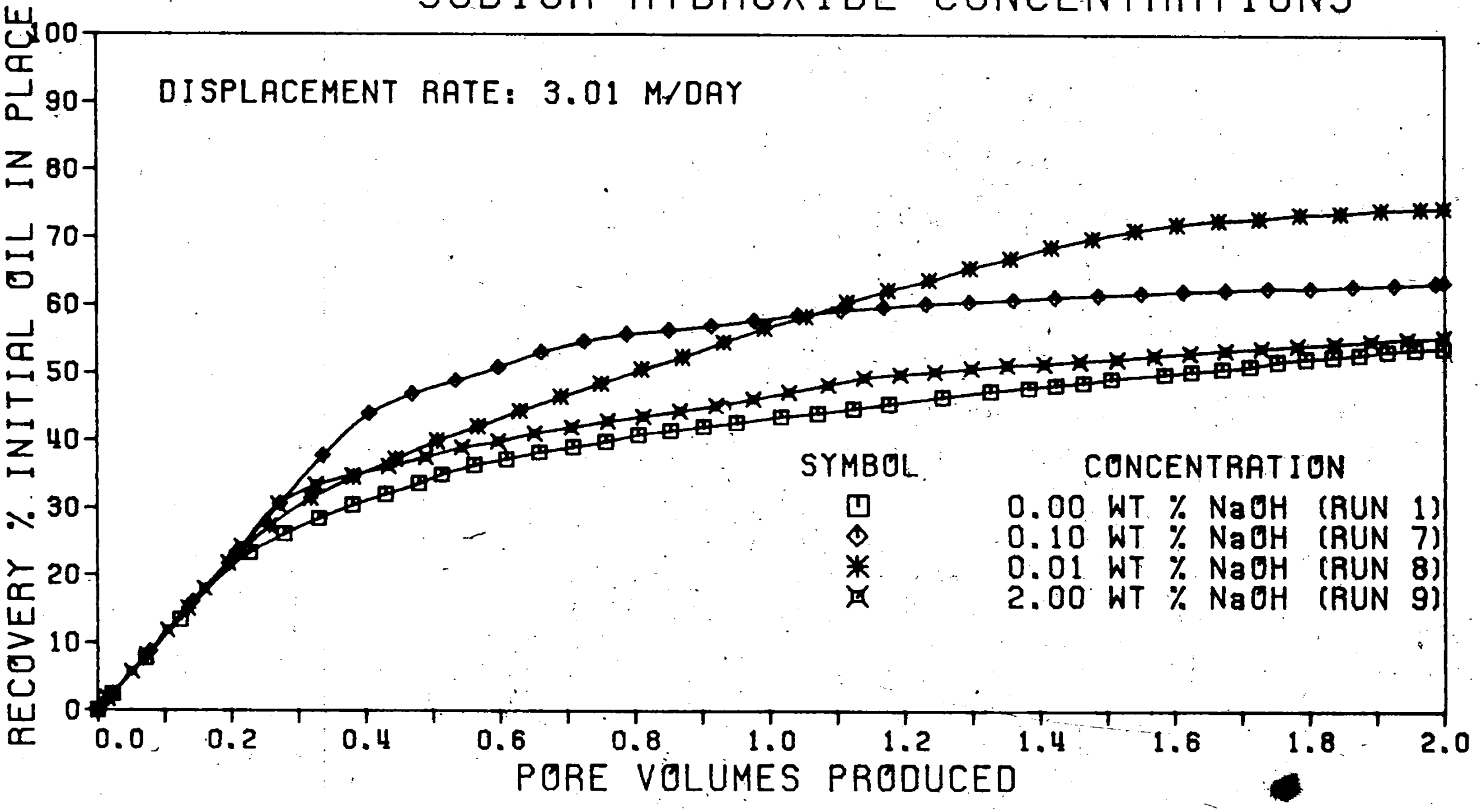
at different apparent linear rates, the rate sensitivity could be further investigated.

It is immediately clear from Figure 8 that the dominant recovery mechanism is significantly affected by the caustic concentration. This figure shows that, at an apparent linear velocity of 3.01 m/day (9.87 ft/day), the 0.01 % by weight solution is superior to the 2.0 or the 0.1 % by weight solutions. The improvement over the 0.1 % case is only evident after the injection of approximately 1.05 pore volumes. As can be seen from the oil cut histories, provided in Appendix C, the breakthrough in Run 8, using 0.01 % caustic, was earlier but, the oil cut was higher for the remainder of the displacement. This trend persisted for all the rates studied but is most apparent in this particular case.

Examination of Figure 7 shows that in all cases the breakthrough recovery for the 0.01 % by weight solution was lower than for the corresponding 0.1 % case. The recovery at 2 pore volumes injected, on the other hand, was higher in all cases, except Run 11 which had essentially the same value as its counterpart, Run 6.

A further interesting point from Figure 7 is that the recovery appears to be more rate sensitive in the 0.01 % by weight system, than in the 0.1 % by weight system. For the former, the recovery at 2 pore volumes injected goes through a maximum at approximately 3 m/day. It appears then, that the floods performed with the 0.01 % by weight caustic

FIG 8 : RECOVERY CURVES FOR DIFFERENT SODIUM HYDROXIDE CONCENTRATIONS



involved a different recovery mechanism from that operating in the 0.1 % case. Possible explanations for this behaviour will be presented in Section 5.5 .

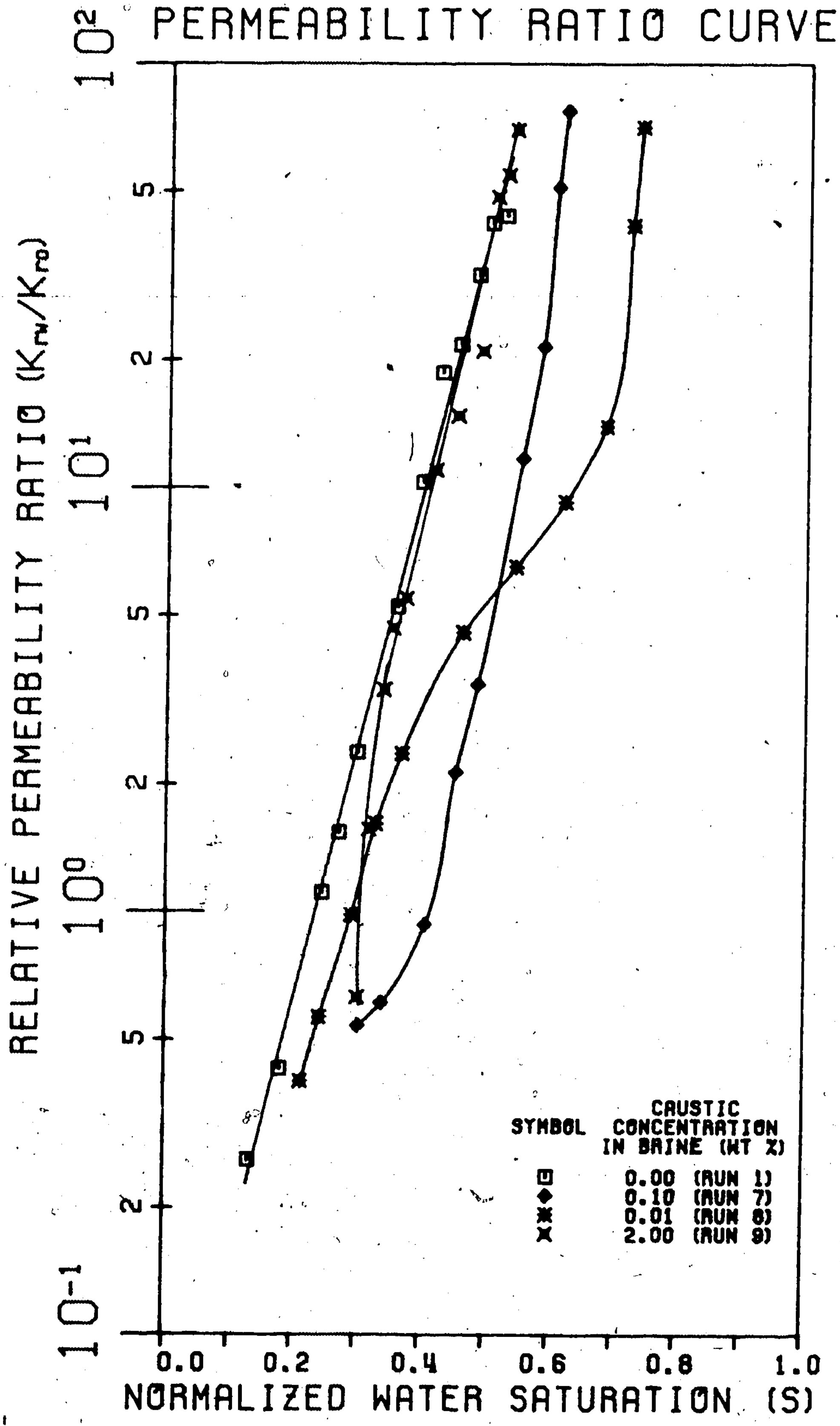
5.4.4 Tests with 2.00 % by Weight Sodium Hydroxide

This run was designed to further examine the effect of caustic concentration on the recovery from the sand/oil/water system under study. It is apparent from both Figure 7 and Figure 8 that there was little significant improvement in oil recovery, over the brine flood, when using the 2.0 % by weight solution.

An examination of the respective relative permeability ratio plots for the brine and 2.0 % caustic floods, Figures C-3 and C-27, shows that there was no major shift in the relative permeability ratio, as was experienced with the other two caustic concentrations. This information is presented in Figure 9. It is also apparent from this figure that despite the fact that breakthrough occurred later in the 2.0 % by weight case, there is little or no improvement in relative permeability ratio beyond a normalized saturation of approximately 0.3 . This is also evident from the recovery curves in Figure 8 where Runs 1 and 9 provide much the same production history.

It appears then, from Run 9, that an excessively large caustic concentration is in fact detrimental to recovery enhancement. Subkow(1942) stated that high electolytic concentrations could prevent the formation of oil-in-water

FIG 9 : RELATIVE PERMEABILITY RATIO CURVES



emulsions, which is an essential step in both the emulsification and entrapment, and emulsification and entrainment recovery mechanisms.

Emulsion formation, reduction of the interfacial tension at the oil-water interface and wettability alterations will all cause a shift in the relative permeability ratio towards a less favourable water mobility. The fact that, for the 2.0 % case, no shift occurred suggests that none of these mechanisms were present in this flood.

5.5 Comparison of the Effect of Rate on the 0.1 and 0.01 % by Weight Tests

The effect of rate on oil recovery may be due to any, or all, of the following factors:

1) Emulsions
2) Viscous forces
3) Capillary forces
4) Adsorption
5) Gravity

The displacements at low flow rates were performed vertically in an attempt to negate the influence of gravity. There is, however, little that can be done to control any of the other factors.

A study of total caustic consumption in the 0.1 % by weight floods shows that the consumption, at this concentration, is insensitive to rate. This total caustic consumption incorporates both adsorption on the sand, and reactions with the oil and sand. There is some scatter in the data, which can be seen on Figure 10, but the general trend is obvious. It thus appears that the system has reached an equilibrium with the flowing caustic stream. The consumption of caustic by reaction with the oil appears to be the major element in the total consumption. The consumption in Run 13, shown as * on Figure 10, when no oil was present, is a full order of magnitude less than the corresponding run with oil present.

It was noted that the apparent linear rate had markedly different effects in the 0.01 % by weight and 0.1 % by weight cases. The differing effects of rate may be seen in Figure 11, where the character of the two curves is notably different, with the 0.1 % by weight flood breaking through later and the percentage of oil in the effluent dropping off quicker than in the 0.01 % by weight case. The recoveries at two pore volumes injected are similiar, 61.4 % for the 0.1 and 61.2 % for the 0.01 % by weight case. This, despite the markedly different oil cut histories. This fact suggests different recovery mechanisms are in play for the two cases.

An examination of the relative permeability ratio curves on Figure 9 shows that the two cases produce curves of different character. The 0.01 % by weight displacement produces an "S" shaped curve, while the 0.1 % by weight displacement yields a slighty concave curve. In both cases, when compared with the brine curve, the curves are shifted

FIG 10 : THE EFFECT OF RATE ON CONSUMPTION

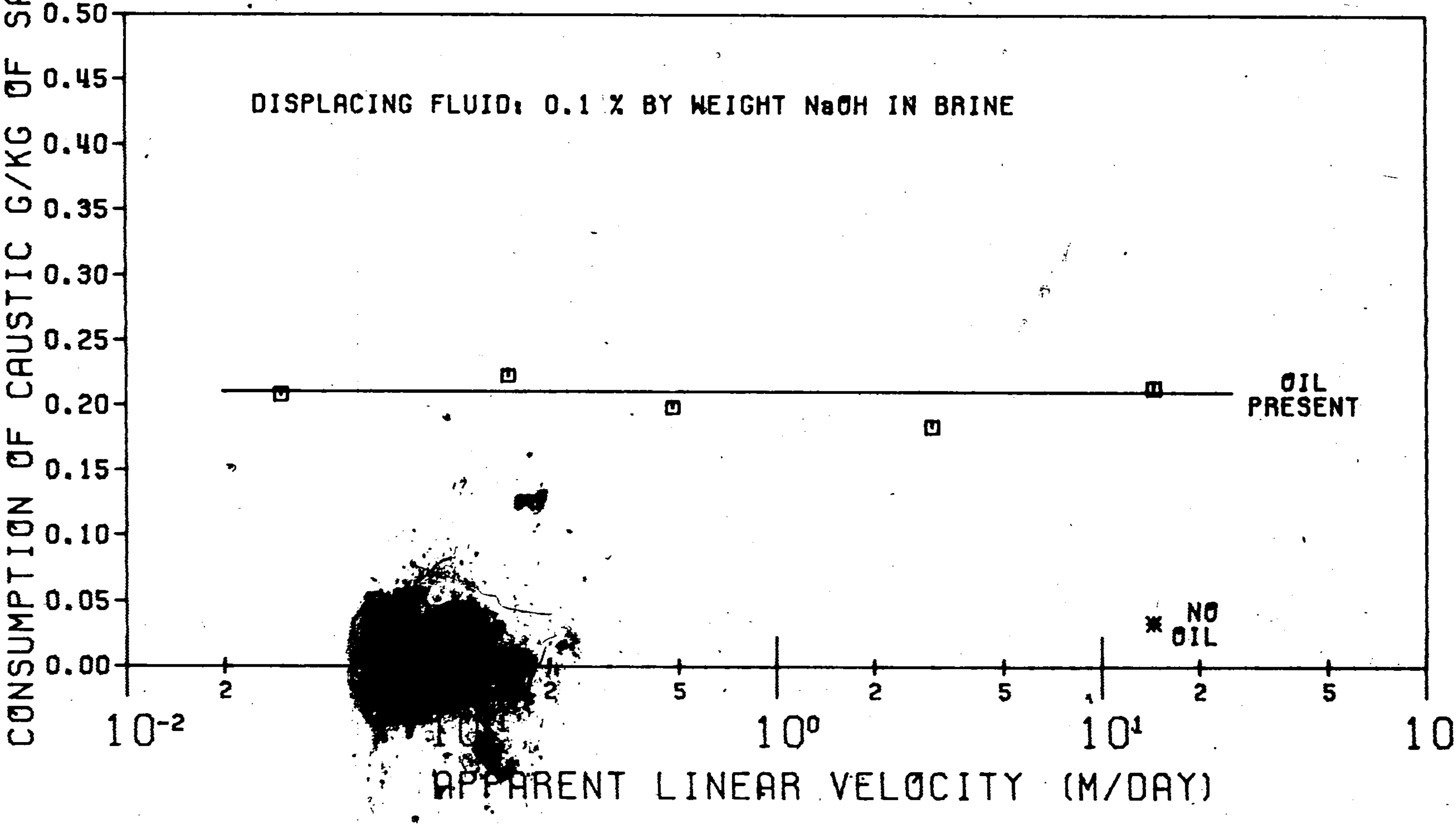
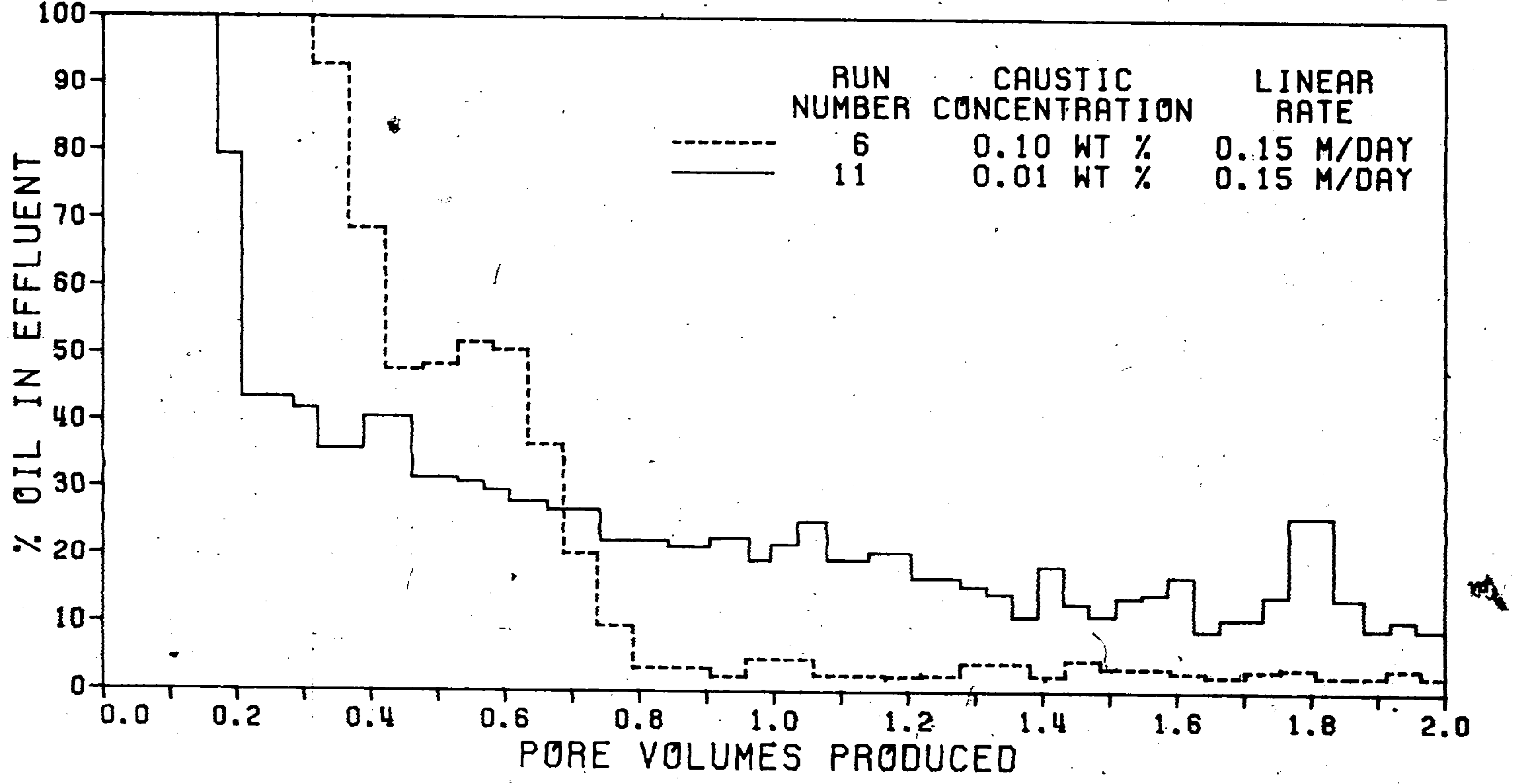


FIG 11 : COMPARISON OF OIL CUT HISTORIES FOR TWO DIFFERENT CAUSTIC CONCENTRATIONS



towards a less favourable water mobility. The crossover of the two caustic curves shows that early in the life of the displacement the 0.1 % case is superior; but in the latter stages, the 0.01 % case is superior.

A possible explanation for this behaviour may be found in the mechanisms in play. It appears that in the 0.1 % system, the improved oil recovery is due to emulsification and entrainment. The interfacial tension is low in this system, and the oil will be emulsified in situ and carried with the flowing alkali and then produced. The fact that no emulsions were observed in the effluent does not rule out this mechanism. The emulsions may have been so unstable that they broke down in the collection tubes. It was noted during the displacements that the effluent took a finite time to separate into distinct oil and water phases.

In the 0.01 % case, on the other hand, the dominant mechanism appears to be emulsification and entrapment. The interfacial tension in this system was higher than that in the 0.1 % case and, as a result, the emulsified oil could not be pushed through the pore throats. It appears from the relative permeability ratio curve on Figure 9 that, the oil droplets block off the swept region, causing the decreased water mobility demonstrated by the flattened section of the curve at intermediate values of normalized saturation. This results in an increased displacement efficiency. The emulsified oil in the entrainment mechanism does not block off the pore throats and, as a result, the oil cut drops off rapidly after breakthrough.

The differing effects of linear rate on recovery are due to these different mechanisms. The entrainment mechanism is essentially independent of rate, as the entrainment process itself is rate independent. The differences in recovery, at the extreme rates, are simply due to the differences in displacement efficiency, which are caused by the viscous and capillary forces. In the entrapment mechanism, however, the linear rate effects the recovery in two ways:

1) The increased rates, under increased gradients, will push the oil droplets through the pore throats, thereby preventing the blocking of these throats.
2) At reduced rates, the caustic consumption will result in the interfacial tension not being sufficiently reduced. This factor is not crucial in the entrainment mechanism because of the magnitude of the input concentration.

In the case of the entrapment mechanism, less sodium hydroxide should be produced as the displacing fluid contacts more of the sandpack. The pH of the effluent was monitored and it is evident that the majority of the caustic was being consumed. Examination of experimental results, in Tables C-1 to C-12, shows a maximum value for C/C_0 of 0.285 (Run 10). This compares with a minimum value of 0.530 in the entrainment displacements.

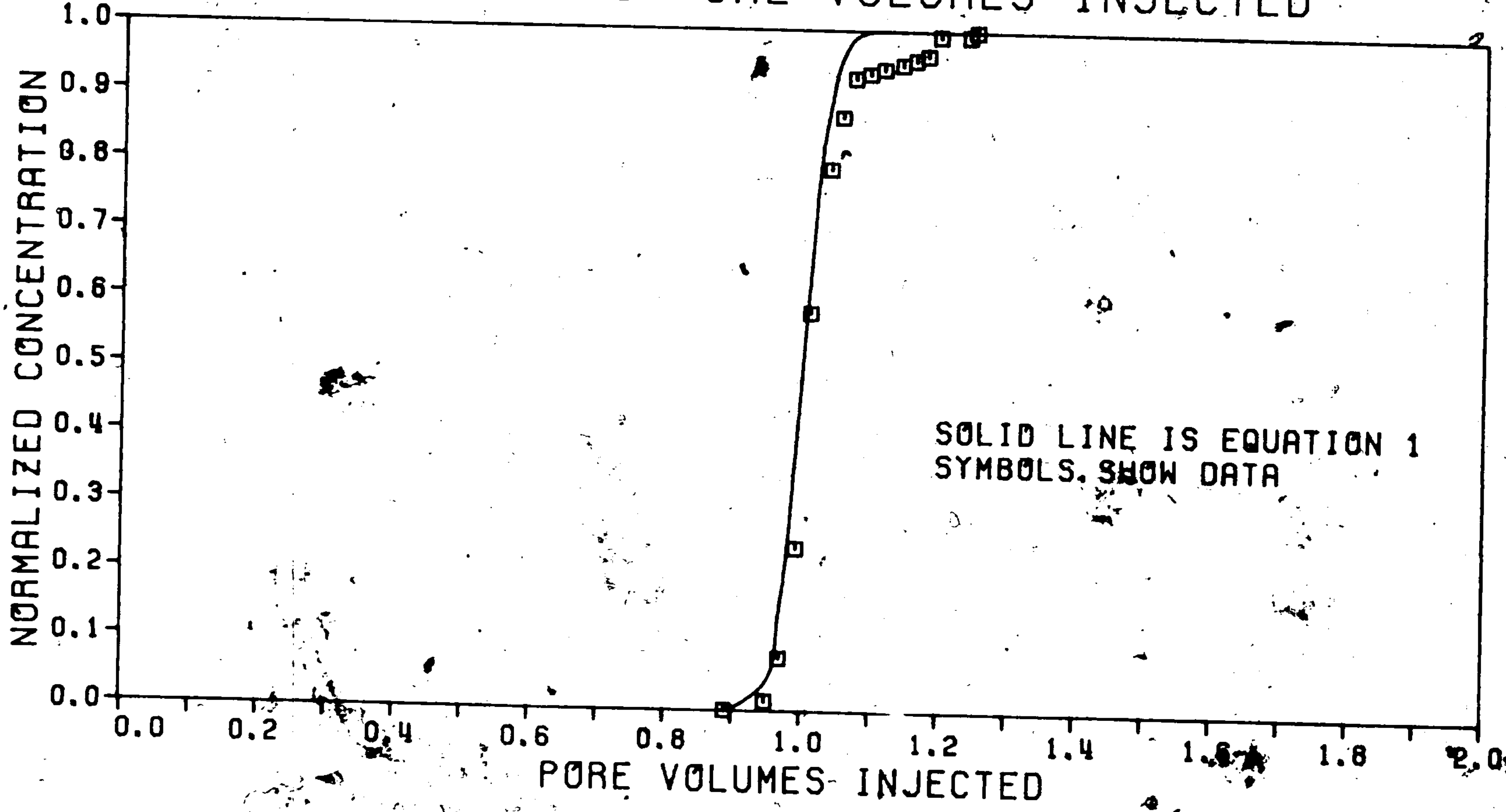
5.6 Adsorption Study

Run 13 was undertaken to quantitatively study the phenomena of caustic dispersion and adsorption in the sandpack. The flood was conducted using 0.1 % by weight sodium hydroxide in brine solution displacing brine. Prior to the caustic flood, the displacement of distilled water by brine, used in the porosity determination, was used to evaluate the dispersion coefficient, D, by the method proposed by Brigham, et al.(1961).

As a check on the value of D, the profile predicted by Equation 1 was plotted on Figure 12 with the experimental data. It is apparent from this figure that the predicted profile is a resonable fit up to high values of normalized concentration. The experimental data exhibits a "tailing off" not predicted by the dispersion equation. This "tail" is due to dead-end spaces in the sandpack, from which the distilled water will diffuse as the brine bypasses it. Therefore it is not pushed ahead by the brine as assumed by the theory. The experimental and theoretical results are also presented in tabular form in Appendix D.

Following the caustic flood the rate constant K_1 was obtained by point matching as described in Section 2.5.4.2 . This procedure to obtain K_1 has a serious shortcoming. In this system the value of C/C_0 at $\xi_0 = 1.0$ is very small, the experimental value being less than 0.02 . At these very low concentrations the accuracy of the readings would be questionable and, as a result, the value of K_1 must also be

FIG 12 : NORMALIZED BRINE CONCENTRATION VERSUS PORE VOLUMES INJECTED



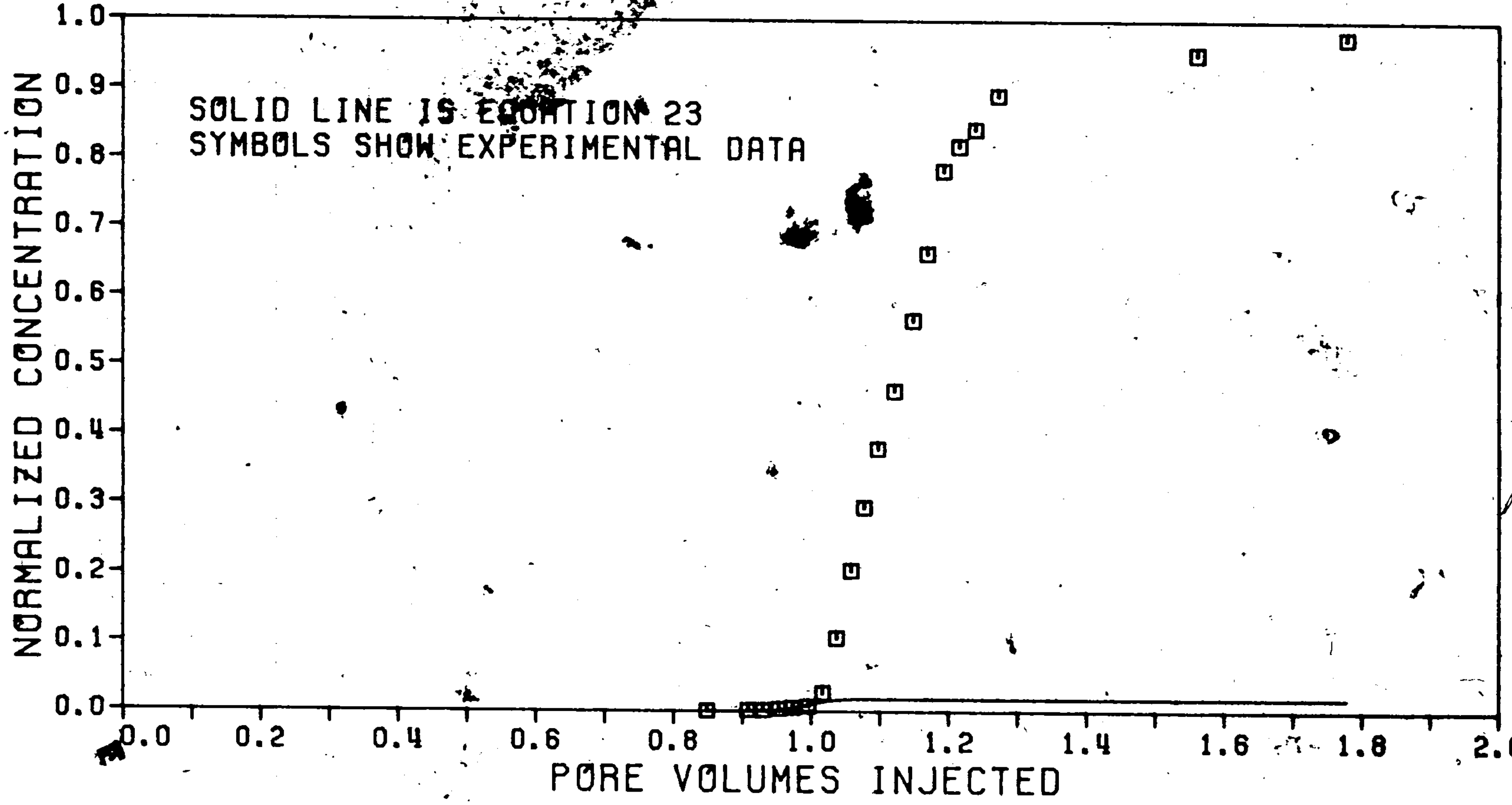
in doubt. This problem is eased somewhat by the relationship in Equation 32 which relates the value of K_1 to the natural log of the concentration. A functional relationship such as this tends to smooth out possible errors.

The experimental caustic concentration profile is shown in Figure 13. In the case of zero adsorption the profile would be identical to that obtained in the brine displacement of distilled water. Comparison of Figures 12 and 13 shows this is not the case. The concentration profile has been shifted to the right. This delay in the caustic breakthrough has been caused by adsorption of the caustic onto the rock surfaces.

The next step was to attempt to fit this experimental profile to the theoretical models. An attempt was first made to use the Case I solution of Banks and Ali(1964), given as Equations (23) to (26). The resulting prediction is shown in Figure 13. It appears from this figure that the prediction is resonable for $\varepsilon_0 < 1.0$. This finding is in agreement with that of Banks and Ali(1964). A possible explanation for the leveling of the predicted profile is that, with $K_2 = 0.0$ in the rate equation, there is no reduction in adsorption rate as C_s increases. The result is, then, that C_s will increase with time until some equilibrium is reached with the passing stream. This value is, however, much higher than that obtained in reality.

Following the failure of the Case I model to accurately predict the experimental results, the logical place to turn

FIG 13 : NORMALIZED CAUSTIC CONCENTRATION VERSUS PORE VOLUMES INJECTED



was the general solution, Equation (20). A value for K_2 was obtained by point matching, but attempts to use the general solution failed due to mathematical difficulties. It was found that the exponential terms of Equations (20) and (21) generated numbers of such extreme magnitude that computation became impossible. Attempts were made to rewrite the equations in more manageable forms, but these met with little success.

Due to the obvious effects of dispersion, the Case II model of Banks and Ali(1964) was not used. This model assumes that there is no dispersion. It is proposed that the dispersion-adsorption equation be solved numerically, using a more appropriate adsorption relationship.

5.7 Experimental Accuracy

It is important in quantitative research, such as this study, to fully appreciate the limitations of the experimental results. The data collected in this study may be divided into 2 sections:

1). Volumetric measurements of the effluent.

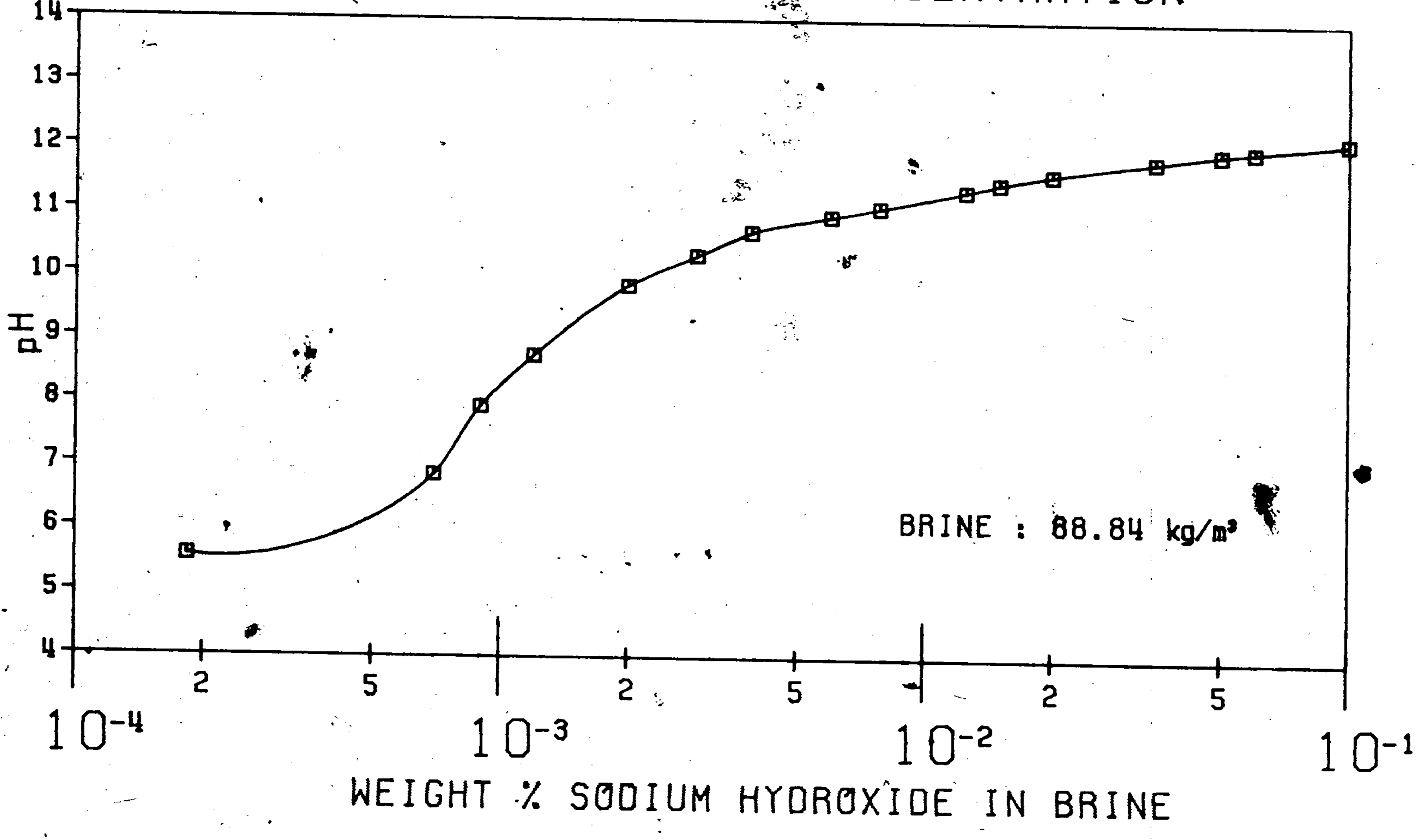
2) Measurement of the effluent concentrations.

The effluent from the displacement tests was collected in 50 ml centrifuge tubes. These tubes allow accuracy of no better than ± 0.5 ml. In the early stages of the displacements, with large oil volumes, this represents a possible error of 1%. In the later stages, however, when oil volumes are reduced to as little as 2% of the effluent, this possible error is much more dramatic. In the case of the production history, any error is damped out by the large cumulative production but, in the calculation of the relative permeability ratio, it is not. This is due to these calculations using the slope of the production history between individual points. To overcome this, these calculations were performed on various average points, obtained by fitting a straight line to 5 data points. The straight line sections were overlapped to provide continuity.

The brine concentration in the effluent (from the porosity determination displacements) was monitored by refractive index. The Spencer Refractometer used, allowed readings to ± 0.0005. This represents a possible error of ± 3.4% in the resulting concentrations.

The caustic concentrations could not be monitored by refractive index as the difference between the indices of the caustic solutions and that of the brine was too small. These concentrations were obtained through pH. The relationship between concentration and pH, as shown in Figure 14, is such that the accuracy would vary from 0.5 % to 11 %. At low values of sodium hydroxide concentration the pH increases rapidly for small increases in concentration, while at higher values the pH increases much more slowly. This means that the possible error increases with caustic concentration. This may lead to considerable errors in the calculation of sodium hydroxide consumption.

FIG 14 : VARIATION OF pH WITH CAUSTIC CONCENTRATION



The consumption of sodium hydroxide in Run 13 may be due to adsorption on and/or reaction with the silica sand. The solubility of silica in hot alkali is reported by Perry and Chilton(1973) to be "very slight". In the system under study, where the displacements were performed at 23°C, the solubility, and as a result the caustic consumption due to the silica, should be negligible.

6. SUMMARY AND CONCLUSIONS

Laboratory caustic floods were conducted in unconsolidated sandpacks saturated with an artificial brine and the Wainwright crude. A displacement of brine by caustic was also performed, to examine the adsorption behaviour. The following conclusions were drawn from the experimental results obtained:

1. The addition of 0.1 and 0.01 % by weight sodium hydroxide to the displacing fluid improves oil recovery.
2. The dominant recovery mechanism appears to be governed by the sodium hydroxide concentration. Emulsification and entrainment is suggested as the dominant recovery mechanism in the 0.1 % by weight displacements, while emulsification and entrapment is used to explain the behaviour of the 0.01 % by weight displacements.
3. The dominant recovery mechanism in the 0.1 % by weight displacements seems to be essentially independent of rate, within the framework of this study.
4. The dominant recovery mechanism in the 0.01 % by weight displacements appears to be rate dependent.
5. In the 0.1 % by weight displacements the total caustic consumption appeared insensitive to rate. The oil present consumed a greater proportion of the total than the sandpack.

6. Consumption of caustic, by adsorption on and/or reaction with the rock did occur during the displacement of brine by 0.1 % by weight caustic.

7. RECOMMENDATIONS

The following possible areas of study are proposed to extend this study:

1. The magnitude of sodium hydroxide adsorption should be examined in relation to both the input concentration and the linear displacement rate.
2. An attempt should be made to improve the mathematical representation of the adsorption phenomenon, with special attention to the rate equation.
3. The effect of rate on smaller sodium hydroxide concentrations should be investigated.
4. The sensitivity of both the adsorption phenomenon and the rate effect to rock type should be examined.

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APPENDIX A

Table A- 1

Properties of Aqueous Fluids

Fluid	Density at 23°C Kg/m³	Viscosity at 23°C mPa.s	Surface Tension N/m
Brine (88.84 Kg/m³ NaCl in distilled water.)	1047.4	1.149	6.12×10^{-2}
0.01 wt % NaOH in brine	1063.7	1.169	6.09×10^{-2}
0.10 wt % N[illegible] in brine	1063.7	1.160	6.05×10^{-2}
2.00 wt % NaOH in brine	1085.9	1.182	6.04×10^{-2}

Table A- 2

Properties of the Dried Crude Oil

Water Content = 0.65 wt %
Surface Tension = 2.91×10^{-2} N/m
Viscosity at 23°C = [illegible]08.3 mPa.S
Density at 23°C = 941.3 kg/m³
Acid Number = 0.527 mg KOH/g
Asphaltene content = 6.06 %

APPENDIX B

Physical Properties of Core Packs

Table B- 1

Physical Properties of Core Packs

Run #	Core #	Length (cm)	Bulk Volume (cc)	Pore Volume (cc)	Porosity (%)	Absolute Permeability (darcys)
1	3	113.0	2254.4	761.7	33.8	17.8
2	3	113.0	2254.4	761.7	33.8	17.8
3	2	105.1	2096.8	701.7	33.5	18.1
4	1	105.1	2088.5	790.0	37.8	22.9
5	4	105.7	2100.4	724.0	34.5	18.5
6	3	113.0	2254.4	810.9	36.0	22.4
7	2	105.1	2096.8	695.5	33.2	19.9
8	4	105.7	2100.4	722.6	34.4	18.1
9	3	113.0	2254.4	809.9	35.9	20.1
10	1	105.1	2096.8	718.4	34.3	19.4
11	4	105.9	2104.4	706.5	33.6	17.7
12	2	106.4	2122.7	742.2	35.0	19.0
13	2	105.1	2096.8	709.2	33.6	16.6

APPENDIX C

Summary of Individual Displacement Tests

TABLE C- 1

CORE 3

RUN 1

CORE PROPERTIES

POROSITY = 33.8 %
PERMEABILITY = 17.8 D
PORE VOLUME = 761.7 ML
INITIAL WATER SAT. = 63.2 ML
INITIAL OIL IN PLACE = 698.5 ML

EXPERIMENTAL VARIABLES

RATE OF INJECTION = 40.0 ML/HR
CONCENTRATION NAOH = 0.00 WT-%
LINEAR RATE = 0.48 M/DAY

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD.	NAOH CONC WT-%	PRESS DROP (PSI)
0.022	16.5	16.5	2.36	0.0	0.0	0.0	100.0			
0.071	37.5	54.0	7.73	0.0	0.0	0.0	100.0			
0.123	39.5	93.5	13.39	0.0	0.0	0.0	100.0			
0.227	69.5	163.0	23.33	10.0	10.0	0.1	87.4			
0.278	19.0	182.0	26.05	20.0	30.0	1.1	48.7			
0.330	16.5	198.5	28.42	22.5	52.5	1.4	42.3			
0.380	14.0	212.5	30.42	24.5	77.0	1.8	36.4			
0.429	11.0	223.5	32.00	26.5	103.5	2.4	29.3			
0.479	11.0	234.5	33.57	26.5	130.0	2.4	29.3			
0.513	9.0	243.5	34.86	17.0	147.0	1.9	34.6			
0.561	10.0	253.5	36.29	27.0	174.0	2.7	27.0			
0.609	6.5	260.0	37.22	30.0	204.0	4.6	17.8			
0.658	6.5	266.5	38.15	30.5	234.5	4.7	17.6			
0.708	6.0	272.5	39.01	32.0	266.5	5.3	15.8			
0.757	5.5	278.0	39.80	32.0	298.5	5.8	14.7			
0.805	7.0	285.0	40.80	30.0	328.5	4.3	18.9			
0.853	4.5	289.5	41.44	32.0	360.5	7.1	12.3			
0.902	4.0	293.5	42.02	33.0	393.5	8.3	10.8			
0.951	4.0	297.5	42.59	33.5	427.0	8.4	10.[illegible]			
1.017	6.0	303.5	43.45	44.0	471.0	7.3	12.0			
1.071	4.0	307.5	44.02	37.0	508.0	9.3	9.8			
1.124	5.0	312.5	44.74	35.5	543.5	7.1	12.3			
1.177	4.5	317.0	45.38	36.0	579.5	8.0	11.1			
1.256	7.0	324.0	46.38	53.0	632.5	7.6	11.7			
1.327	6.5	330.5	47.31	47.5	680.0	7.3	12.0			
1.384	3.5	334.0	47.81	40.0	720.0	11.4	8.0			
1.424	3.0	337.0	48.24	28.0	748.0	9.3	9.7			

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TABLE C- 1 CONTINUED

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	WOR	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
1.465	2.5	339.5	48.60	28.5	776.5	11.4	8.1			
1.506	4.5	344.0	49.25	27.0	803.5	6.0	14.3			
1.585	4.5	348.5	49.89	55.5	859.0	12.3	7.5			
1.625	2.5	351.0	50.25	28.0	887.0	11.2	8.2			
1.671	3.0	354.0	50.68	31.5	918.5	10.5	8.7			
1.712	3.0	357.0	51.11	28.5	947.0	9.5	[illegible].5			
1.753	4.5	361.5	51.75	27.0	974.0	6.0	14.3			
1.795	3.0	364.5	52.18	28.5	1002.5	9.5	9.5			
1.835	2.0	366.5	52.47	29.0	1031.5	14.5	6.5			
1.875	2.5	369.0	52.82	28.0	1059.5	11.2	8.2			
1.916	3.0	372.0	53.25	28.0	1087.5	9.3	9.7			
1.957	2.5	374.5	53.61	29.0	1116.5	11.6	7.9			
1.998	2.0	376.5	53.90	29.0	1145.5	14.5	6.5			

FIG C.1 : RECOVERY AS A FUNCTION OF PORE VOLUMES INJECTED

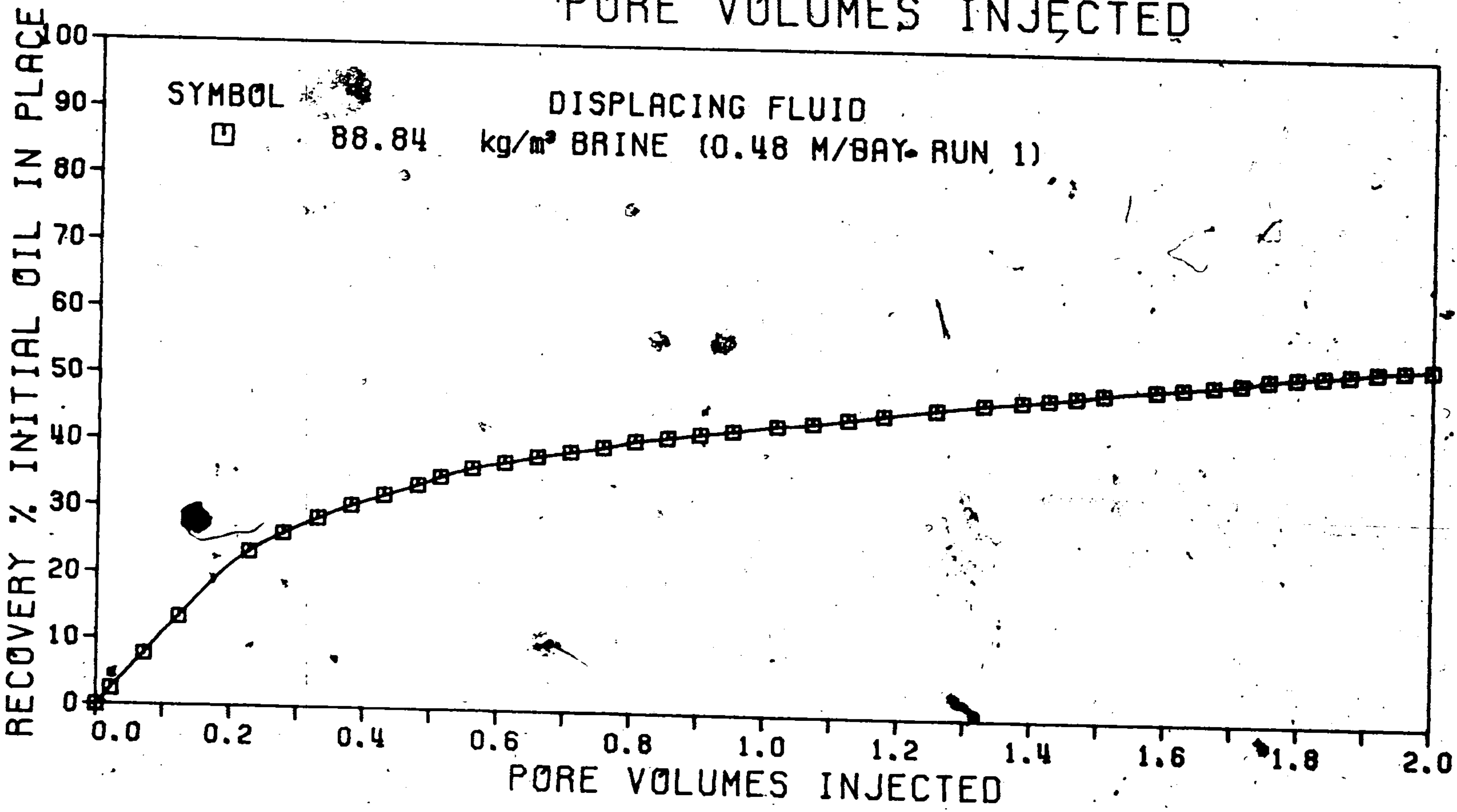

FIG C.2 : OIL CUT HISTORY FOR RUN 1

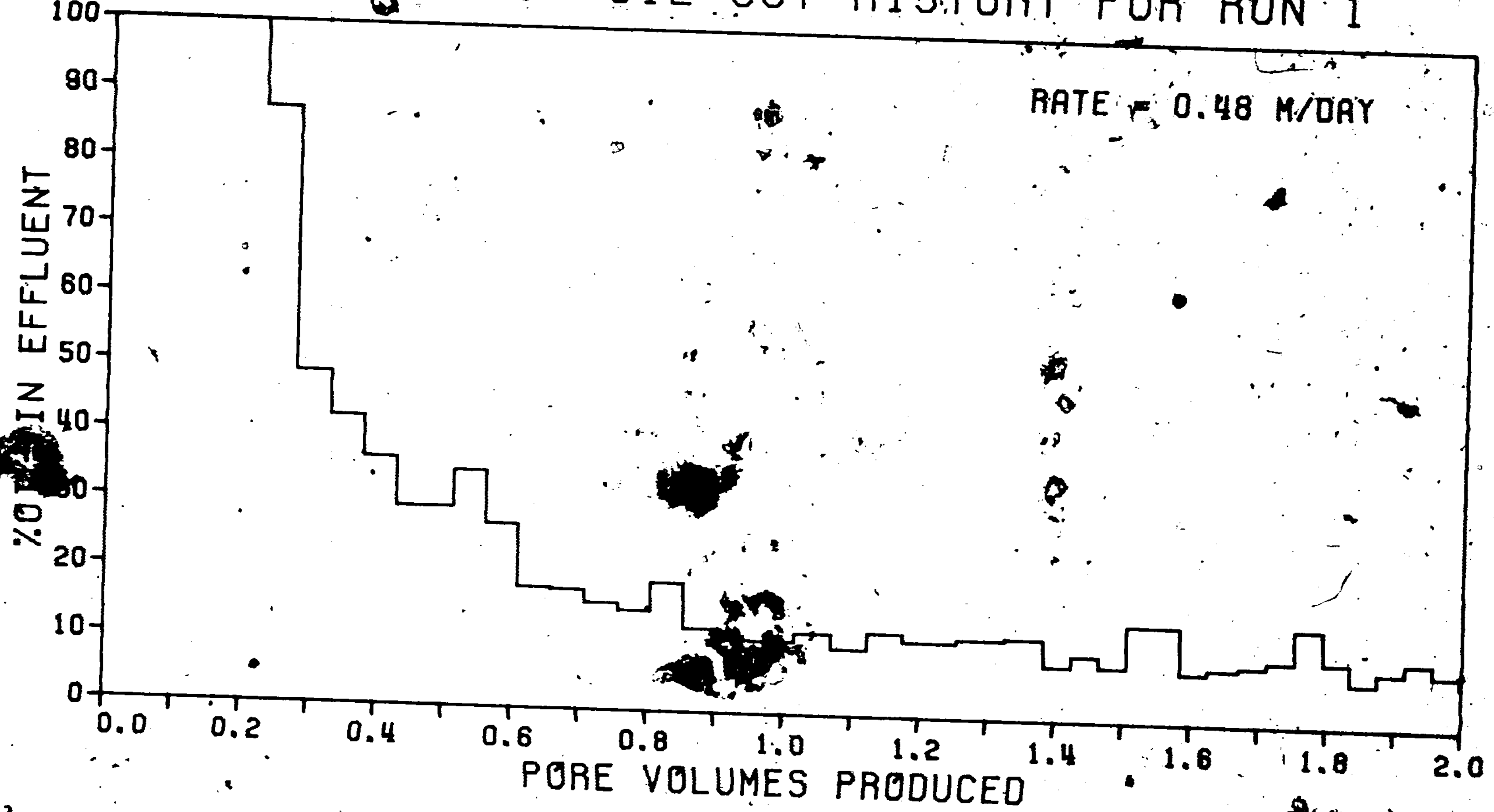

FIG C.3 : RELATIVE PERMEABILITY RATIO RUN 1

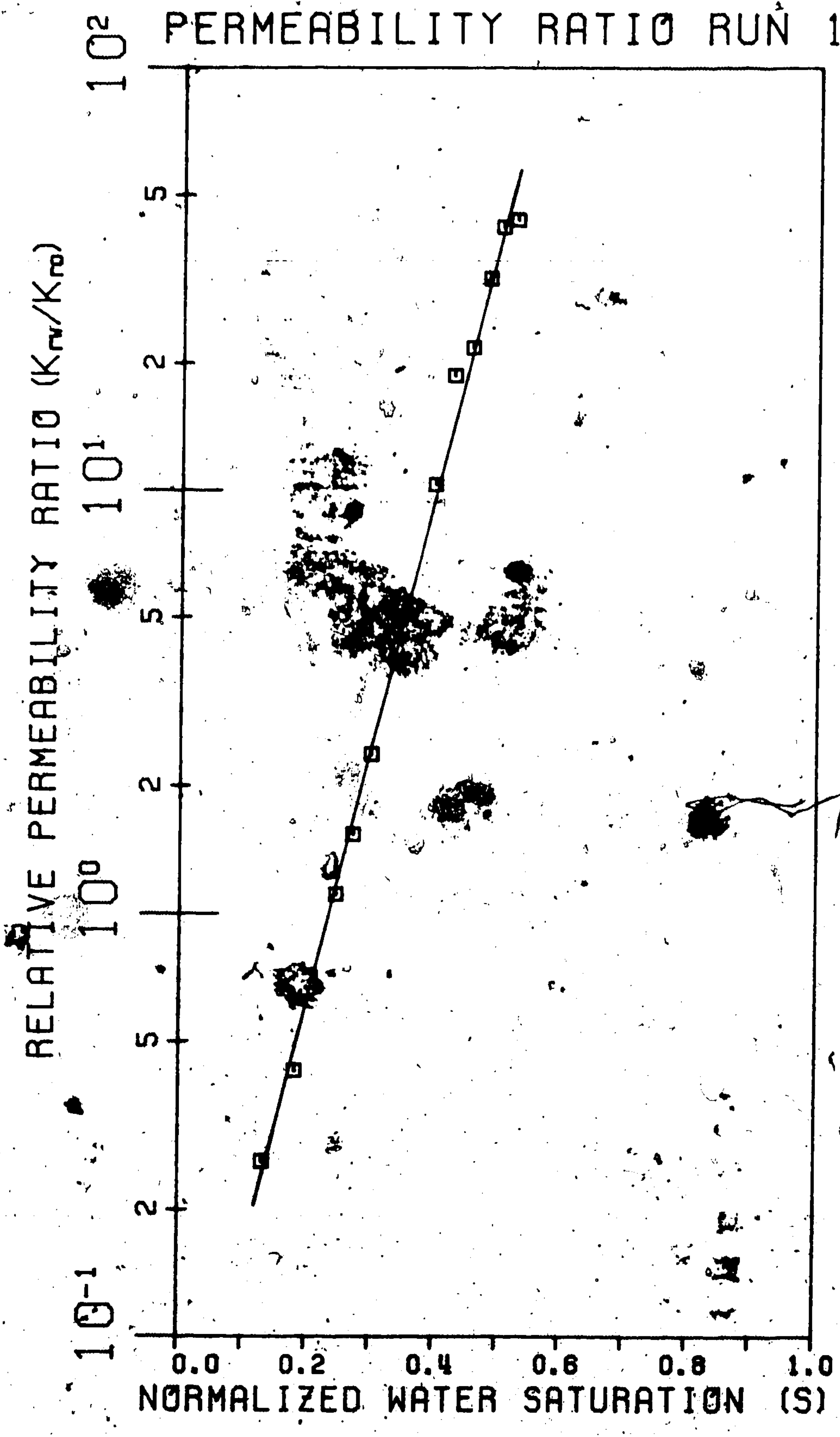

TABLE C- 2

CORE 3

RUN 2

CORE PROPERTIES
POROSITY = 33.8 %
PERMEABILITY = 17.8 D
PORE VOLUME = 761.7 ML
INITIAL WATER SAT. = 64.7 ML
INITIAL OIL IN PLACE = 697.0 ML

EXPERIMENTAL VARIABLES
RATE OF INJECTION = 40.0 ML/HR
CONCENTRATION NAOH = 0.10 WT-%
LINEAR RATE = 0.48 M/DAY

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	[illegible].O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
0.014	11.0	11.0	1.58	0.0	0.0	0.0	100.0			
0.093	60.0	71.0	10.19	0.0	0.0	0.0	100.0			
0.198	80.0	151.0	21.66	0.0	0.0	0.0	100.0			
0.297	72.5	223.5	32.06	2.5	2.5	0.0	96.7			58.2
0.351	31.5	255.0	36.58	9.5	12.0	0.3	[illegible].8			
0.402	22.5	277.5	39.81	16.5	28.5	0.7	57.7	6.79	0.00066	
0.456	23.0	300.5	43.11	18.0	46.5	0.8	56.1	8.70	0.00116	
0.508	17.5	318.0	45.62	22.5	69.0	1.3	43.8	9.94	0.00215	
0.557	15.0	333.0	47.77	22.0	91.0	1.5	40.5	10.99	0.00650	
0.609	20.5	353.5	50.71	19.0	110.0	0.9	51.9	11.46	0.01500	
0.654	11.0	364.5	52.29	23.5	133.5	2.1	31.9			
0.707	5.0	369.5	53.01	35.5	169.0	7.1	12.3			4.5
0.754	3.5	373.0	53.51	32.5	201.5	9.3	9.7			4.2
0.803	2.0	375.0	53.80	35.0	236.5	17.5	5.4	11.61	0.02050	
0.866	3.0	378.0	54.23	45.0	28[illegible]	15.0	6.3			
0.935	2.5	380.5	54.59	50.0	331.5	20.0	4.8			
0.982	1.0	381.5	54.73	35.0	366.5	35.0	2.8			
1.036	1.0	382.5	54.87	40.5	407.0	40.5	2.4			
1.105	4.0	386.5	55.45	48.0	455.0	12.0	7.7			3.0
1.165	4.0	390.5	56.02	42.0	497.0	10.5	8.7			
1.226	4.0	394.5	56.60	42.5	539.5	10.6	8.6			
1.280	3.0	397.5	57.03	38.0	577.5	12.7	7.3	11.79	0.03150	
1.340	4.0	401.5	57.60	41.5	619.0	10.4	8.8			
1.380	3.0	404.5	58.03	28.0	647.0	9.3	9.7			
1.421	2.5	407.[illegible]	58.39	28.5	[illegible].5	11.4	8.1			
1.461	2.0	409.0	58.68	28.0	7[illegible].5	14.0	6.7			
1.499	2.0	4[illegible]	58.96	27.5	731.0	13.8	6.8			

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TABLE C- 2 CONTINUED

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
1.577	4.0	415.0	59.54	55.0	786.0	13.8	6.8			
1.617	2.5	417.5	59.90	28.0	814.0	11.2	8.2			
1.656	3.0	420.5	60.33	27.0	841.0	9.0	10.0			
1.696	2.0	422.5	60.61	28.0	869.0	14.0	6.7	11.83	0.03600	
1.736	2.5	425.0	60.97	28.5	897.5	11.4	8.1			
1.776	2.0	427.0	61.26	28.0	925.5	14.0	6.7	11.88	0.04000	
1.816	2.5	429.5	61.62	28.0	953.5	11.2	8.2			
1.856	2.0	431.5	61.90	28.5	982.0	14.3	6.6			
1.895	1.5	433.0	62.12	28.5	1010.5	19.0	5.0			
1.936	2.0	435.0	62.41	29.5	1040.0	14.8	6.3			
1.976	1.5	436.5	62.62	28.5	1068.5	19.0	5.0			
2.005	1.0	437.5	62.77	21.0	1089.5	21.0	4.5	12.11	0.08200	

FIG C.4 : RECOVERY AS A FUNCTION OF PORE VOLUMES INJECTED

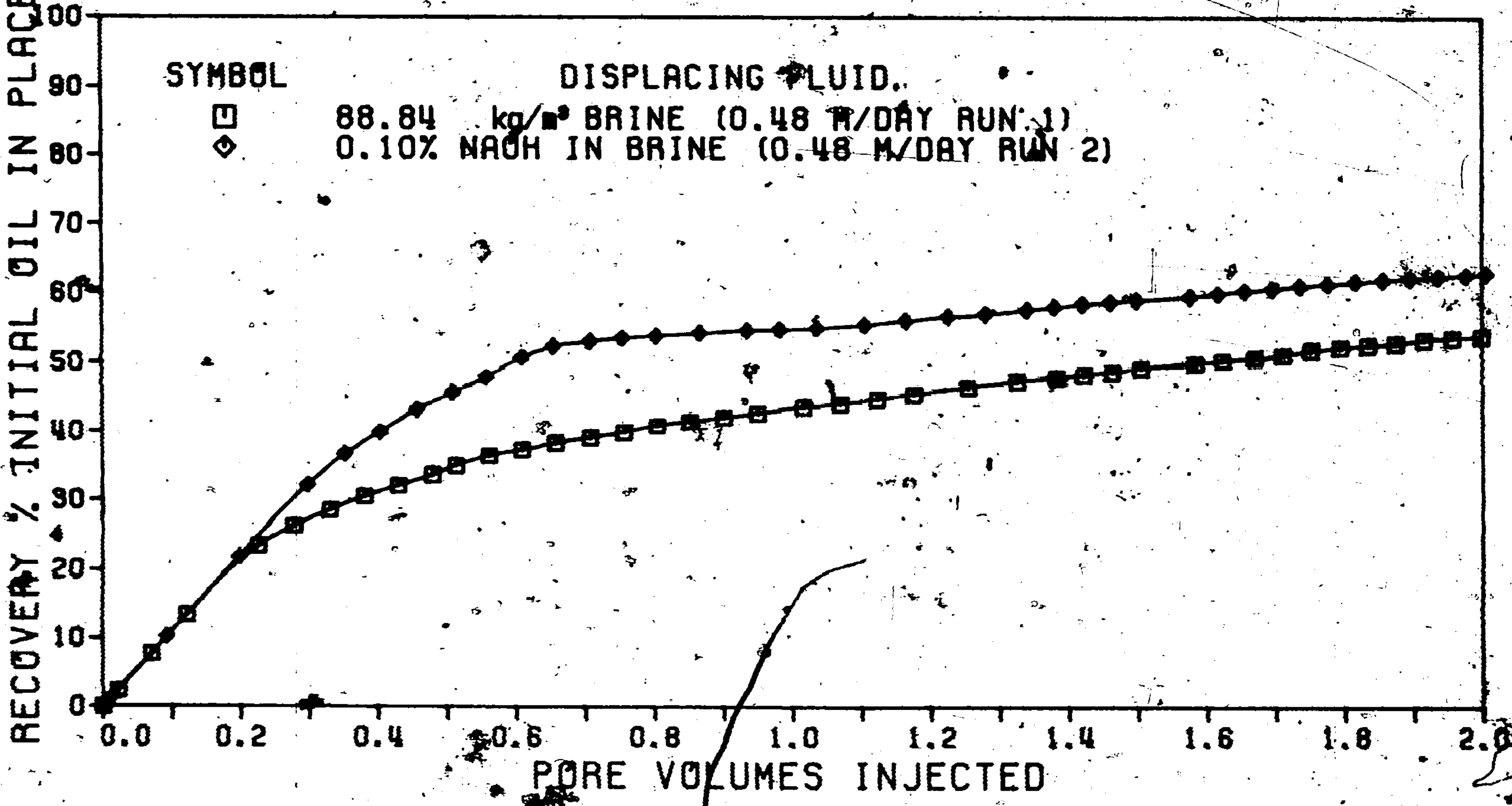

FIG C.5 : PRESSURE AND OIL CUT HISTORIES FOR RUN 2

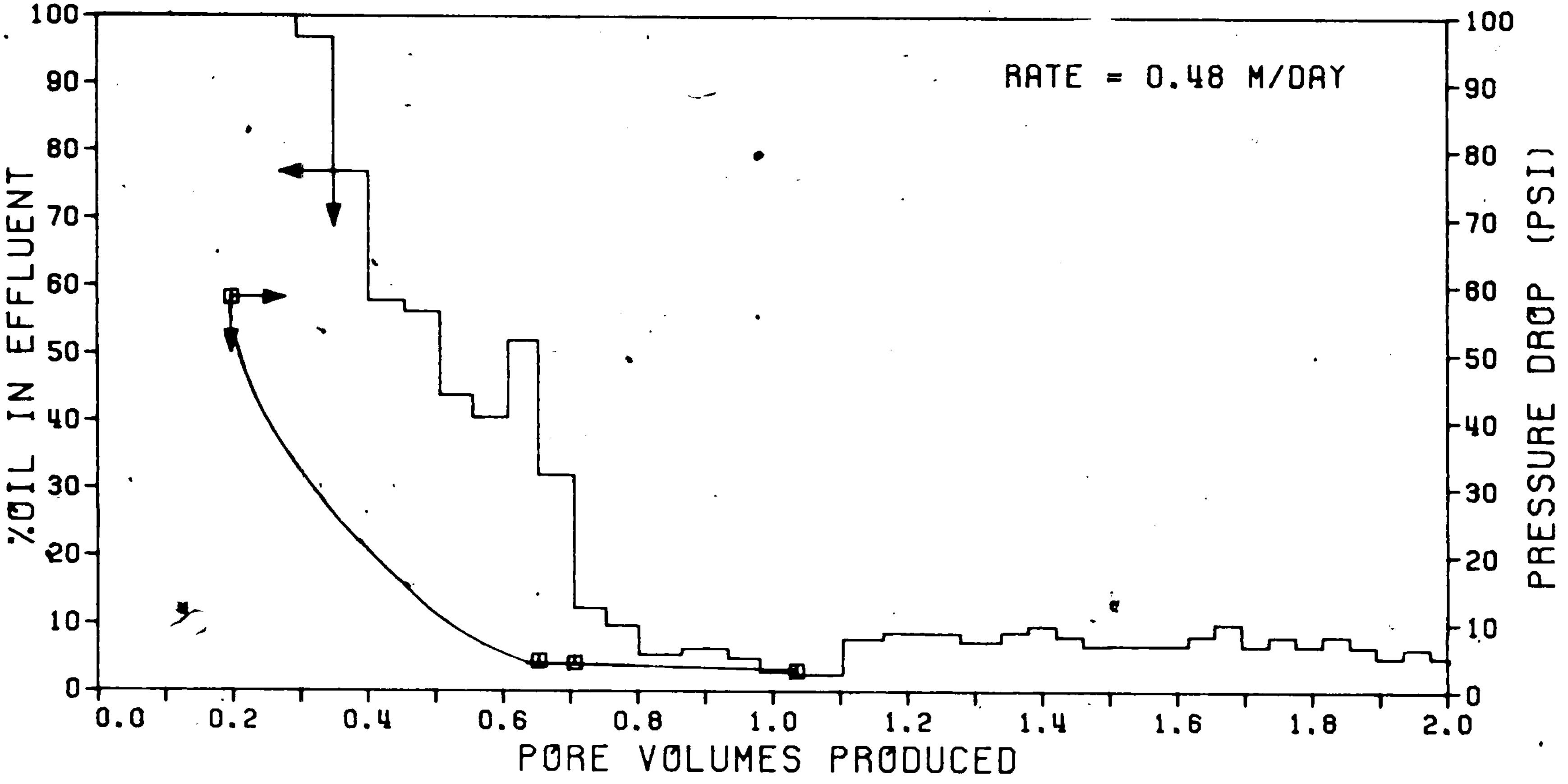

FIG C.6 : RELATIVE PERMEABILITY RATIO RUN 2

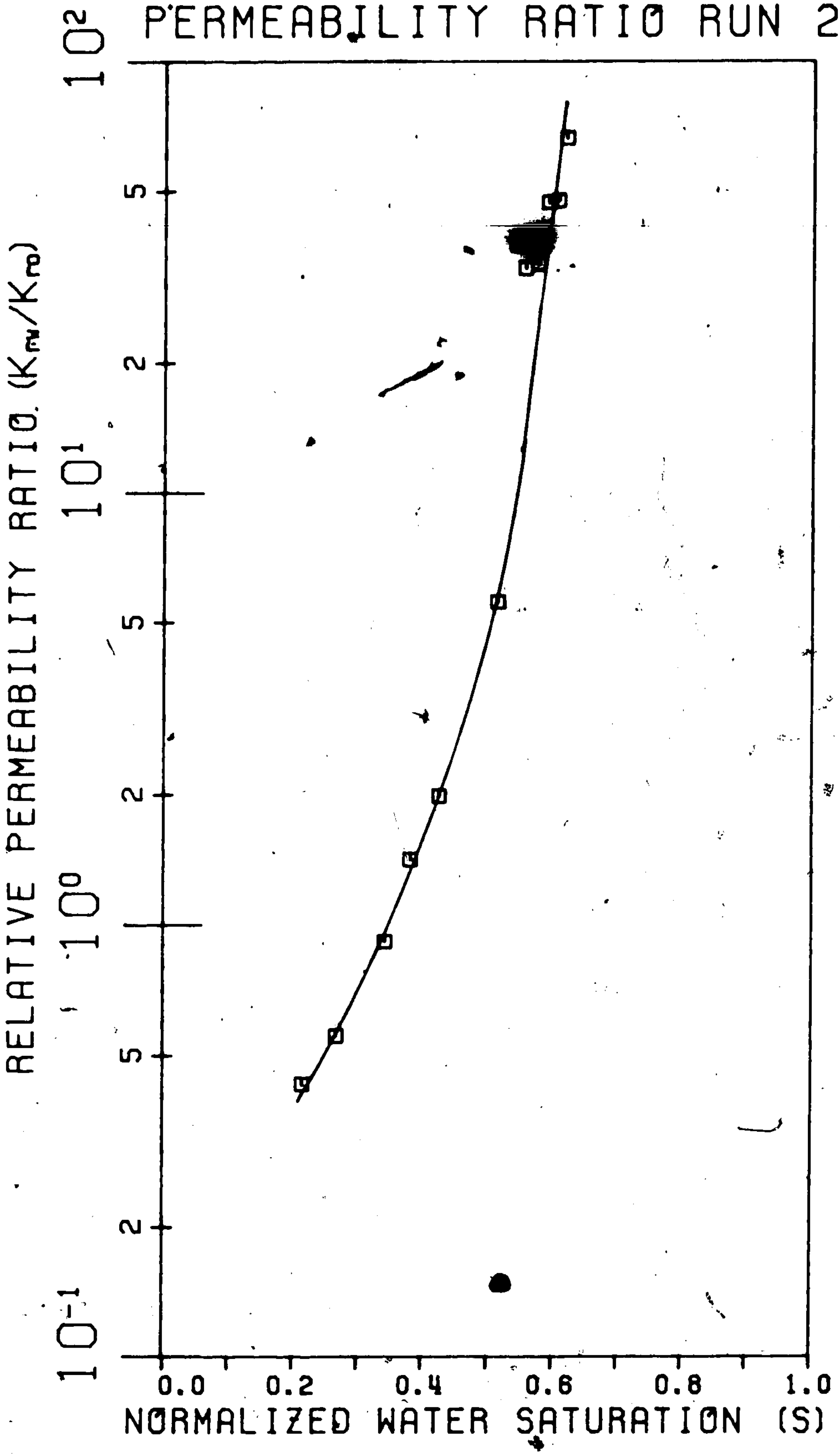

TABLE C- 3

CORE 2 RUN 3

CORE PROPERTIES

POROSITY = 33.5 %
PERMEABILITY = 18.1 D
PORE VOLUME = 701.7 ML
INITIAL WATER SAT. = 108.1 ML
INITIAL OIL IN PLACE = 593.6 ML

EXPERIMENTAL VARIABLES

RATE OF INJECTION = 40.0 ML/HR
CONCENTRATION NAOH = 0.10 WT-%
LINEAR RATE = 0.48 M/DAY

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
0.055	38.5	38.5	6.49	0.0	0.0	0.0	100.0			20.0
0.111	39.5	78.0	13.14	0.0	0.0	0.0	100.0			17.0
0.171	42.0	120.0	20.22	0.0	0.0	0.0	100.0			15.0
0.235	45.0	165.0	27.80	0.0	0.0	0.0	100.0			10.3
0.266	21.5	186.5	31.42	0.0	0.0	0.0	100.0			
0.316	35.5	222.0	37.40	0.0	0.0	0.0	100.0			
0.367	28.0	250.0	42.12	7.5	7.5	0.3	78.9			8.3
0.425	23.0	273.0	45.99	18.0	25.5	0.8	56.1	6.79	0.00066	6.5
0.483	22.0	295.0	49.70	18.5	44.0	0.8	54.3	8.30	0.00101	4.8
0.537	16.0	311.0	52.39	22.0	66.0	1.4	42.1	9.99	0.00220	
0.591	11.5	322.5	54.33	26.0	92.0	2.3	30.7	10.96	0.00610	4.3
0.644	10.0	332.5	56.01	27.5	119.5	2.8	26.7	11.50	0.01570	4.3
0.698	8.0	340.5	57.36	30.0	149.5	3.8	21.1	11.64	0.02300	
0.751	6.0	346.5	58.37	31.0	180.5	5.2	16.2			
0.804	7.0	353.5	59.55	30.0	210.5	4.3	18.9	11.78	0.03000	3.3
0.854	4.0	357.5	60.23	31.5	242.0	7.9	11.3			
0.904	2.0	359.5	80.56	33.0	275.0	16.5	5.7			
0.956	2.0	361.5	60.90	34.0	309.0	17.0	5.6	11.84	0.03750	
1.005	1.5	363.0	61.15	33.0	342.0	22.0	4.3			
1.055	1.0	364.0	61.32	34.5	376.5	34.5	2.8	11.91	0.04400	
1.107	1.0	365.0	61.49	35.5	412.0	35.5	2.7			
1.158	1.5	366.5	61.74	34.0	446.0	22.7	4.2			
1.209	1.0	367.5	61.91	35.0	481.0	35.0	2.8			
1.261	1.5	369.0	62.16	35.0	516.0	23.3	4.1			
1.313	1.5	370.5	62.42	34.5	550.5	23.0	4.2	11.99	0.05700	
1.363	1.0	371.5	62.58	34.5	585.0	34.5	2.8			
1.418	1.5	373.0	62.84	37.0	622.0	24	3.9			

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TABLE C- 3 CONTINUED

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
1.474	1.5	374.5	63.09	37.5	659.5	25.0	3.8			
1.533	2.0	376.5	63.43	40.0	699.5	20.0	4.8			
1.592	2.0	378.5	63.76	39.0	738.5	19.5	4.9			
1.652	2.0	380.5	64.10	40.0	778.5	20.0	4.8			
1.711	2.0	382.5	64.44	39.5	818.0	19.8	4.8	12.02	0.06500	
1.770	2.0	384.5	64.77	39.5	857.5	19.8	4.8			
1.829	0.5	385.0	64.86	41.0	898.5	82.0	1.2			
1.888	1.0	386.0	65.03	40.0	938.5	40.0	2.4			
1.947	1.5	387.5	65.28	40.0	978.5	26.7	3.6			
2.006	1.0	388.5	65.45	40.5	1019.0	40.5	2.4	12.06	0.07000	

FIG C.7 : RECOVERY AS A FUNCTION OF PORE VOLUMES INJECTED

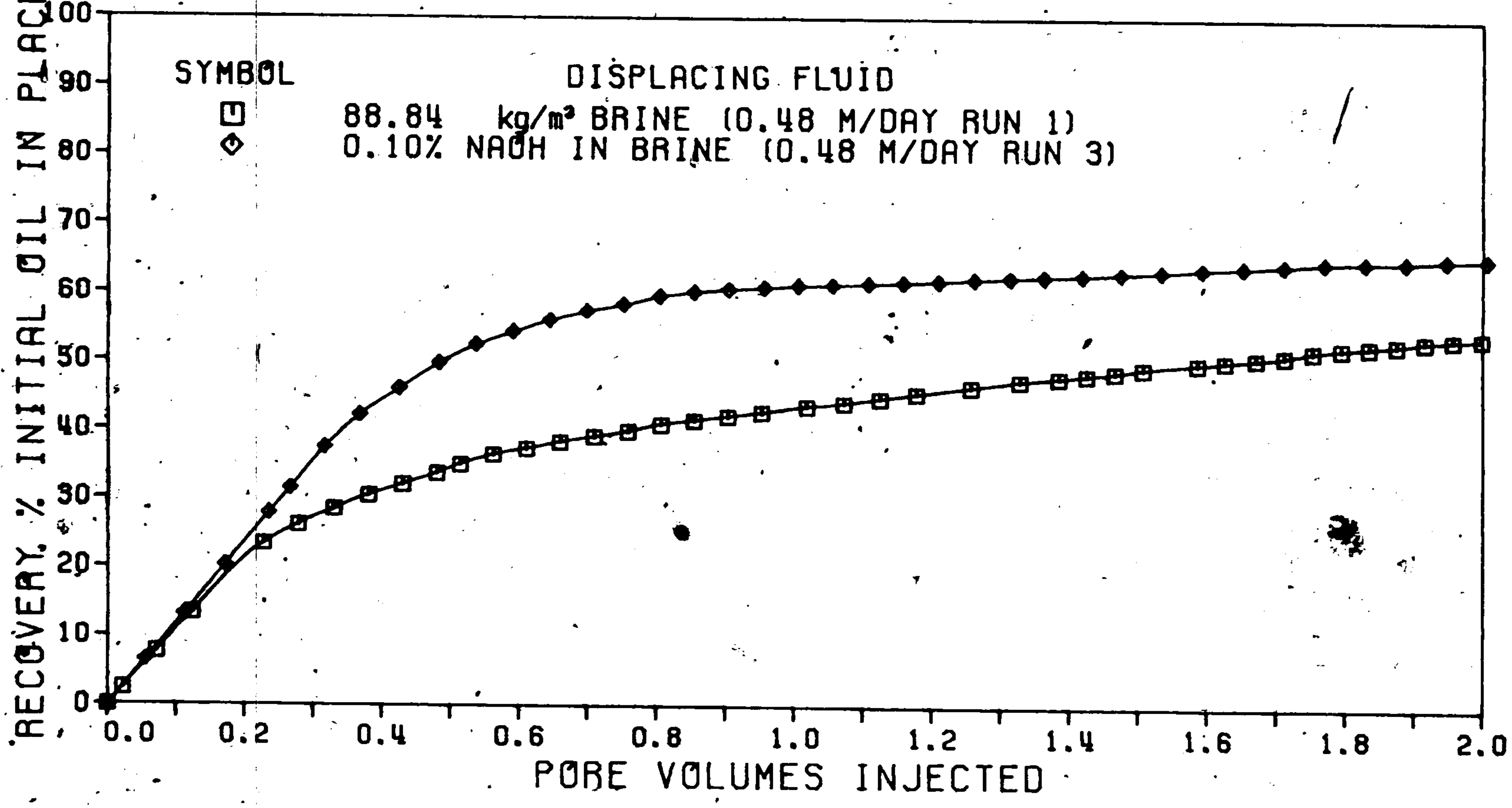

FIG C.8 : PRESSURE AND OIL CUT
HISTORIES FOR RUN 3

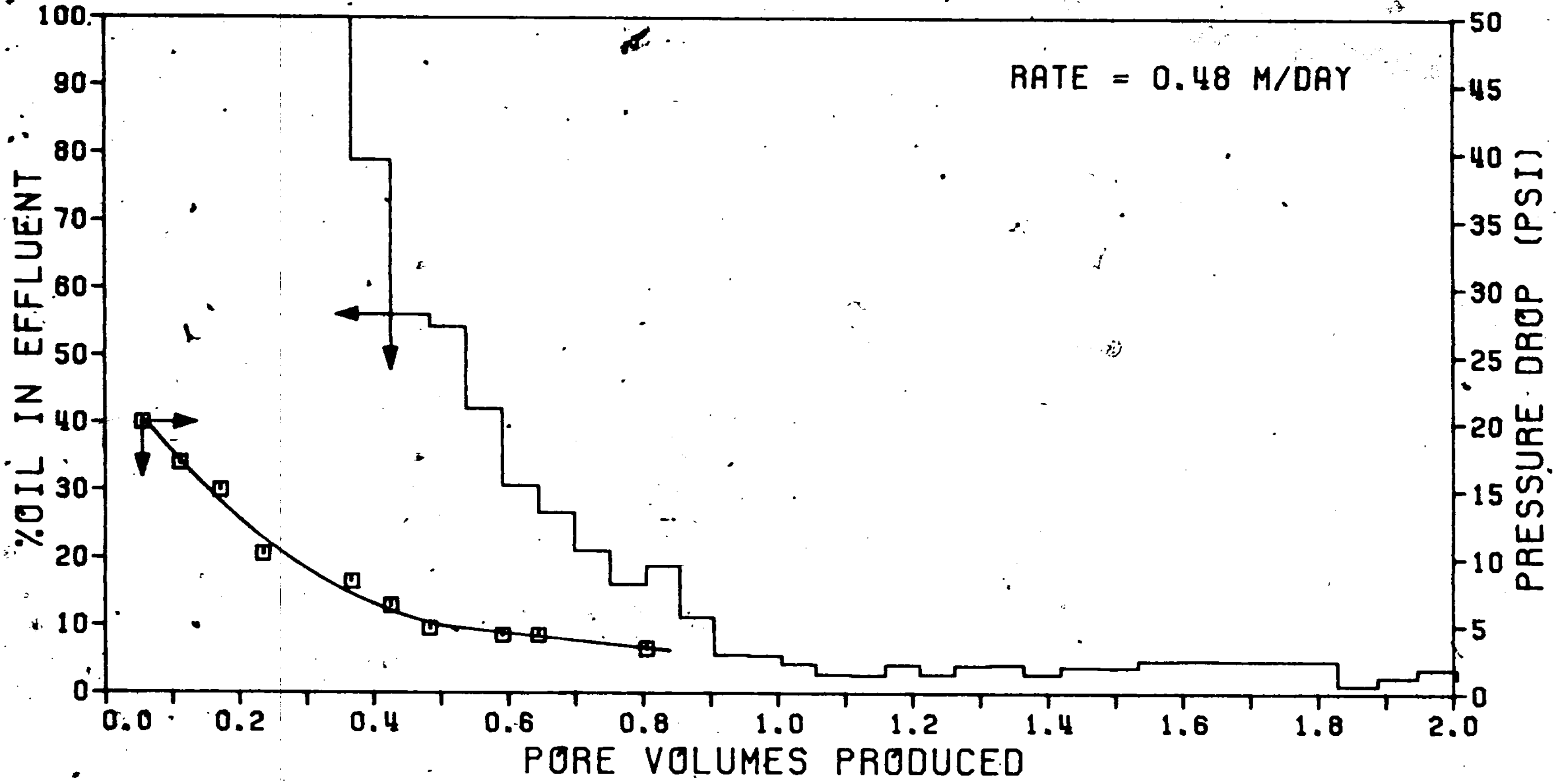

FIG C.9 : RELATIVE PERMEABILITY RATIO RUN 3

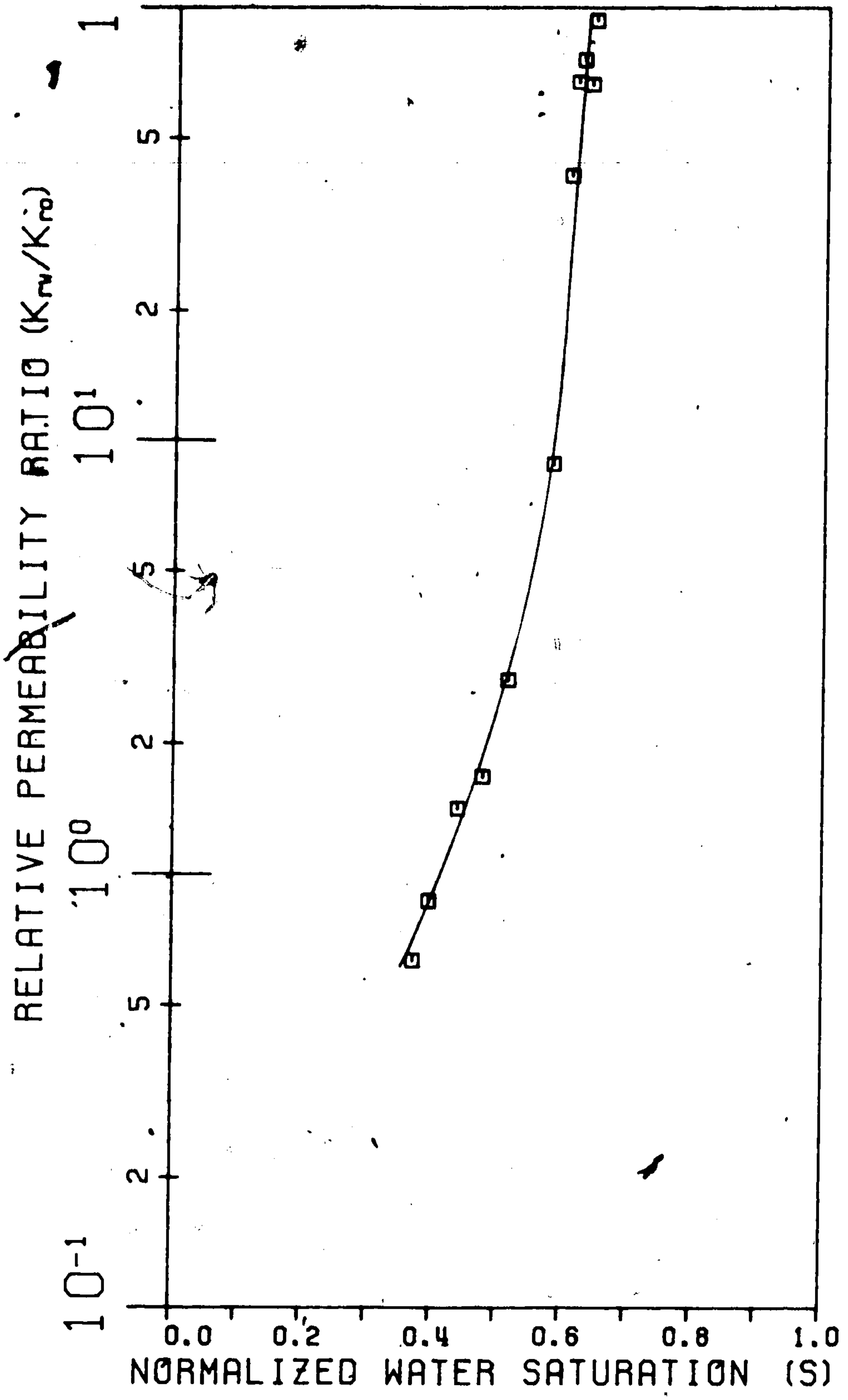

TABLE C-4

CORE 1

RUN 4

CORE PROPERTIES

POROSITY = 37.7 %
PERMEABILITY = 22.9 D
PORE VOLUME = 790.0 ML
INITIAL WATER SAT = 115.0 ML
INITIAL OIL IN PLACE = 675.0 ML

EXPERIMENTAL VARIABLES

RATE OF INJECTION = 2.5 ML/HR
CONCENTRATION NAOH = 0.10 WT-%
LINEAR RATE = 0.03 M/DAY

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
0.053	41.5	41.5	6.15	0.0	0.0	0.0	100.0			
0.079	21.0	62.5	9.26	0.0	0.0	0.0	100.0			
0.116	29.5	92.0	13.63	0.0	0.0	0.0	100.0			
0.182	51.5	143.5	21.26	0.0	0.0	0.0	100.0			
0.243	48.5	192.0	28.44	0.0	0.0	0.0	100.0			
0.276	26.0	218.0	32.30	0.0	0.0	0.0	100.0			
0.332	44.5	262.5	38.89	0.0	0.0	0.0	100.0			
0.347	12.0	274.5	40.67	0.0	0.0	0.0	100.0			
0.403	25.5	300.0	44.44	18.5	18.5	0.7	58.0	6.29	0.00051	
0.444	11.5	311.5	46.15	20.5	39.0	1.8	35.9	6.35	0.00053	
0.502	11.0	322.5	47.78	35.0	74.0	3.2	23.9	6.86	0.00068	
0.538	6.0	328.5	48.67	22.5	96.5	3.8	21.1	7.30	0.00076	
0.594	5.5	334.0	49.48	39.0	135.5	7.1	12.4	7.50	0.00080	
0.651	4.5	338.5	50.15	40.5	176.0	9.0	10.0	7.73	0.00085	
0.722	3.0	341.5	50.59	53.0	229.0	17.7	5.4	9.43	0.00162	
0.794	2.0	343.5	50.89	55.0	284.0	27.5	3.5	11.52	0.01700	
0.864	2.5	346.0	51.26	52.5	336.5	21.0	4.5	11.85	0.03800	
0.950	1.5	347.5	51.48	66.5	403.0	44.3	2.2			
1.009	3.0	350.5	51.93	44.0	447.0	14.7	6.4	11.94	0.05000	
1.065	7.0	357.5	52.96	37.0	484.0	5.3	15.9	11.97	0.05200	
1.121	7.0	364.5	54.00	37.0	521.0	5.3	15.9			
1.177	7.0	371.5	55.04	37.0	558.0	5.3	15.9	11.99	0.05700	
1.234	7.5	379.0	56.15	37.5	595.5	5.0	16.7			
1.284	5.0	384.0	56.89	35.0	630.5	7.0	12.5			
1.344	7.0	391.0	57.93	40.0	670.5	5.7	14.9	12.02	0.06500	
1.403	3.5	394.5	58.44	43.0	713.5	12.3	7.5			
1.463	7.0	401.5	59.48	41.0	754.5	5.9	14.6	12.03	0.06700	

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TABLE C- 4 CONTINUED

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
1.517	6.0	407.5	60.37	36.5	791.0	6.1	14.1			
1.577	6.5	414.0	61.33	40.5	831.5	6.2	13.8			
1.621	5.5	419.5	62.15	29.5	861.0	5.4	15.7			
1.669	5.5	425.0	62.96	32.5	893.5	5.9	14.5			
1.725	6.5	431.5	63.93	38.0	931.5	5.8	14.6			
1.768	5.0	436.5	64.67	28.5	960.0	5.7	14.9			
1.828	6.0	442.5	65.56	42.0	1002.0	7.0	12.5	12.06	0.07000	
1.884	5.0	447.5	66.30	39.0	1041.0	7.8	11.4			
1.925	4.5	452.0	66.96	27.5	1068.5	6.1	14.1			
1.972	4.0	456.0	67.56	33.5	1102.0	8.4	10.7			
2.005	3.5	459.5	68.07	22.5	1124.5	6.4	13.5			

FIG C.10 : RECOVERY AS A FUNCTION OF PORE VOLUMES INJECTED

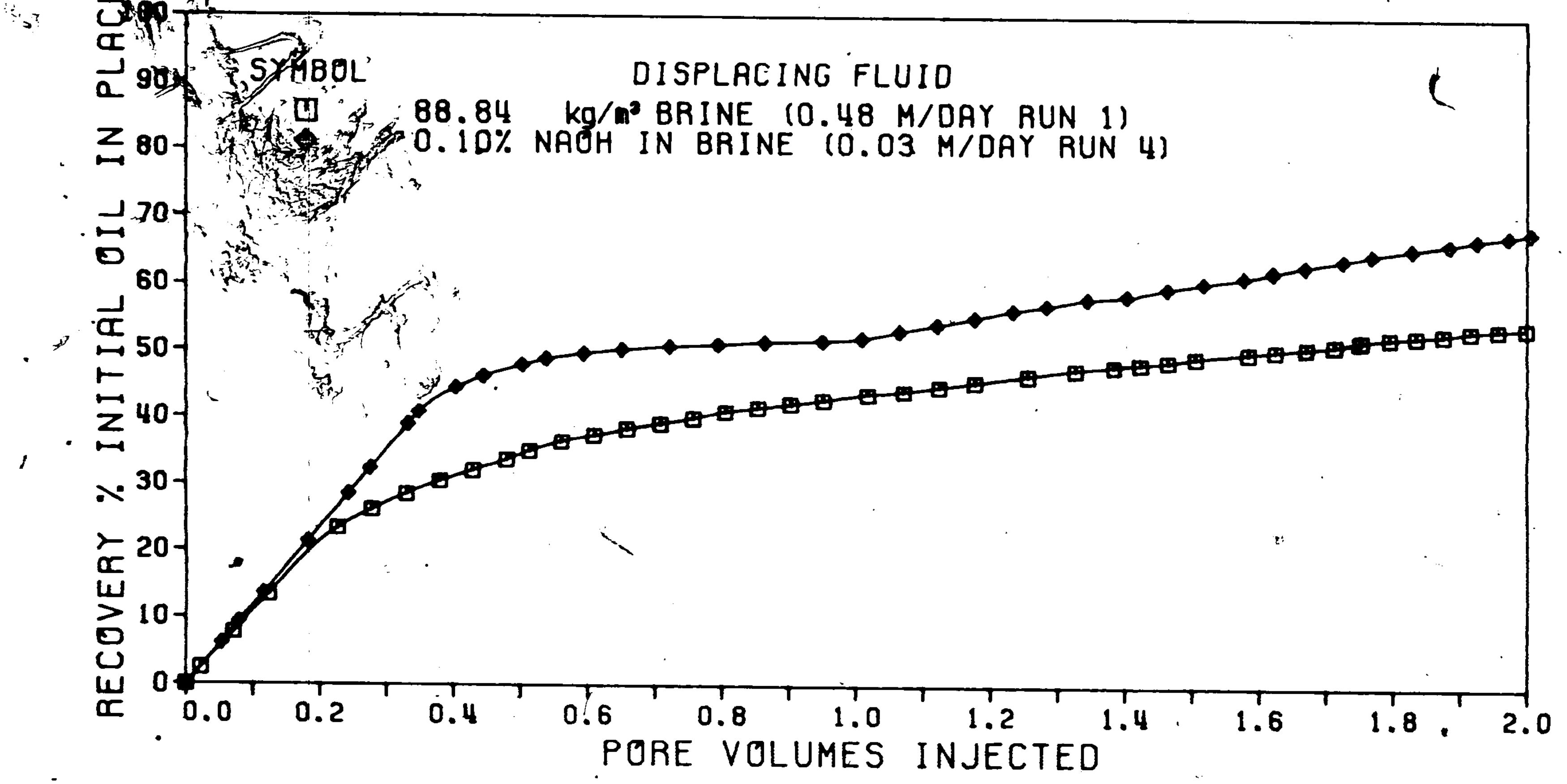

FIG C.11 : OIL CUT HISTORY FOR RUN 4

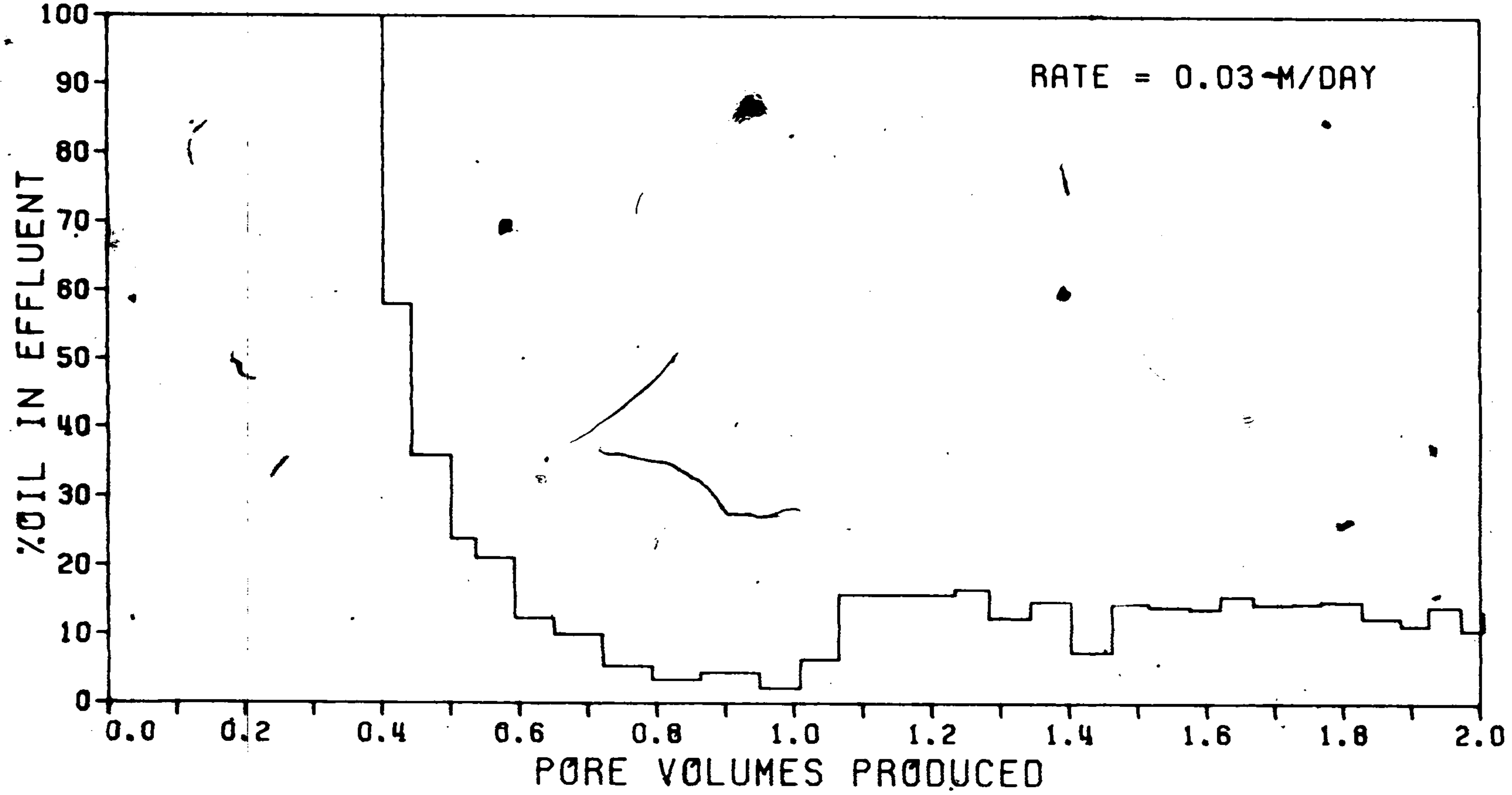

FIG C.12 : RELATIVE PERMEABILITY RATIO RUN 4

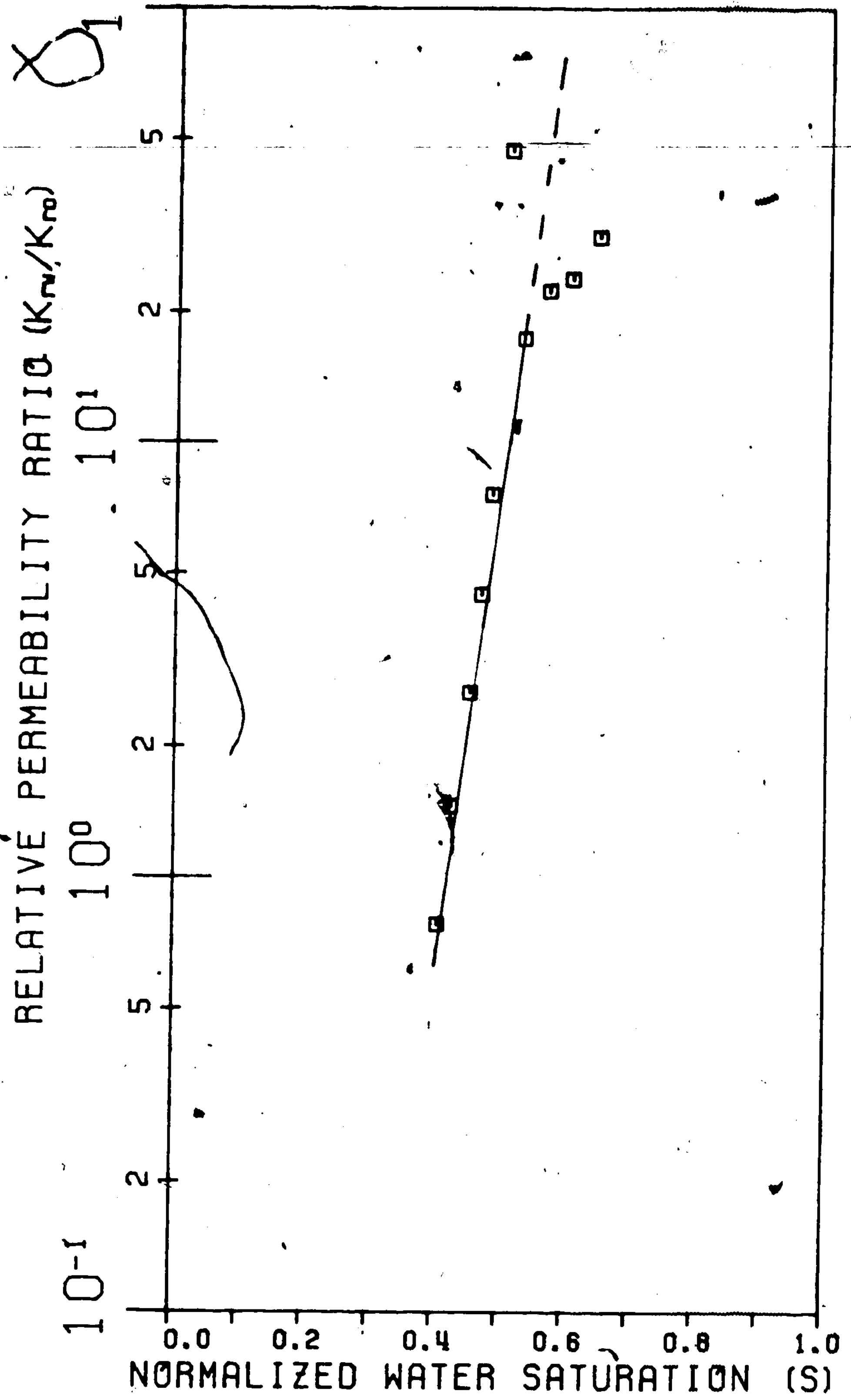

TABLE C- 5

CORE 4

RUN 5

CORE PROPERTIES
POROSITY = 34.5 %
PERMEABILITY = 18.1 D
PORE VOLUME = 724.0 ML
INITIAL WATER SAT = 94.0 ML
INITIAL OIL IN PLACE = 630.0 ML

EXPERIMENTAL VARIABLES
RATE OF INJECTION = 1200.0 ML/HR
CONCENTRATION NAOH = 0.10 WT-%
LINEAR RATE = 14.49 M/DAY

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
0.065	47.0	47.0	7.46	0.0	0.0	0.0	100.0			307.0
0.128	45.5	92.5	14.68	0.0	0.0	0.0	100.0			210.0
0.184	41.0	133.5	21.19	0.0	0.0	0.0	100.0			200.0
0.241	37.0	170.5	27.06	4.0	4.0	0.1	90.2	9.21	0.00145	150.0
0.299	21.0	191.5	30.40	21.0	25.0	1.0	50.0	11.34	0.01217	115.0
0.362	13.0	204.5	32.46	32.5	57.5	2.5	28.6	11.59	0.01950	104.0
0.421	11.5	216.0	34.29	31.0	88.5	2.7	27.1	11.71	0.02600	96.0
0.481	11.5	227.5	36.11	32.5	121.0	2.8	26.1			[illegible].0
0.540	11.5	239.0	37.94	31.0	152.0	2.7	27.1	11.75	0.02800	86.0
0.603	12.0	251.0	39.84	33.5	185.5	2.8	26.4			80.0
0.664	11.5	262.5	41.67	33.0	218.5	2.9	25.8	11.76	0.02800	77.0
0.723	10.5	273.0	43.33	32.0	250.5	3.0	24.7			72.0
0.789	9.5	282.5	44.84	38.5	289.0	4.1	19.8			70.0
0.856	8.5	291.0	46.19	39.5	328.5	4.6	17.7			65.0
0.9[illegible]6	7.5	298.5	47.38	36.5	365.0	4.9	17.0	11.80	0.03200	62.0
0.979	7.0	305.5	48.49	38.5	403.5	5.5	15.4			61.0
1.041	6.5	312.0	49.52	38.5	442.0	5.9	14.4			60.5
1.105	6.0	318.0	50.48	40.0	482.0	6.7	13.0			60.0
1.162	5.5	323.5	51.35	36.0	518.0	6.5	13.3			59.0
1.221	6.0	329.5	52.30	36.5	554.5	6.1	14.1	11.61	0.02050	
1.287	6.5	336.0	53.33	41.0	595.5	6.3	13.7			55.0
1.349	3.5	339.5	53.89	42.0	637.5	12.0	7.7	11.76	0.02850	53.0
1.410	4.0	343.5	54.52	40.0	677.5	10.0	9.1			51.0
1.477	6.0	349.5	55.48	42.0	719.5	7.0	12.5			49.5
1.540	5.0	354.5	56.27	41.0	760.5	8.2	10.9	11.88	0.04000	48.5
1.605	5.0	359.5	57.06	42.0	802.5	8.4	10.6			47.5
1.664	4.0	363.5	57.70	38.5	841.0	9.6	9.4	11.89	0.04200	47.0

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TABLE C- 5 CONTINUED

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %OIIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
1.724	3.0	366.5	58.17	41.0	882.0	13.7	6.8			45.0
1.790	4.5	371.0	58.89	43.0	925.0	9.6	9.5			43.0
1.855	4.0	375.0	59.52	43.0	968.0	10.8	8.5	11.91	0.04400	41.0
1.916	3.5	378.5	60.08	40.5	1008.5	11.6	8.0			
1.982	4.0	382.5	60.71	44.0	1052.5	11.0	8.3			38.0
2.000	1.1	383.6	60.89	11.9	1064.4	10.8	8.5	11.97	0.05200	37.0

FIG C.13 : RECOVERY AS A FUNCTION OF
PORE VOLUMES INJECTED

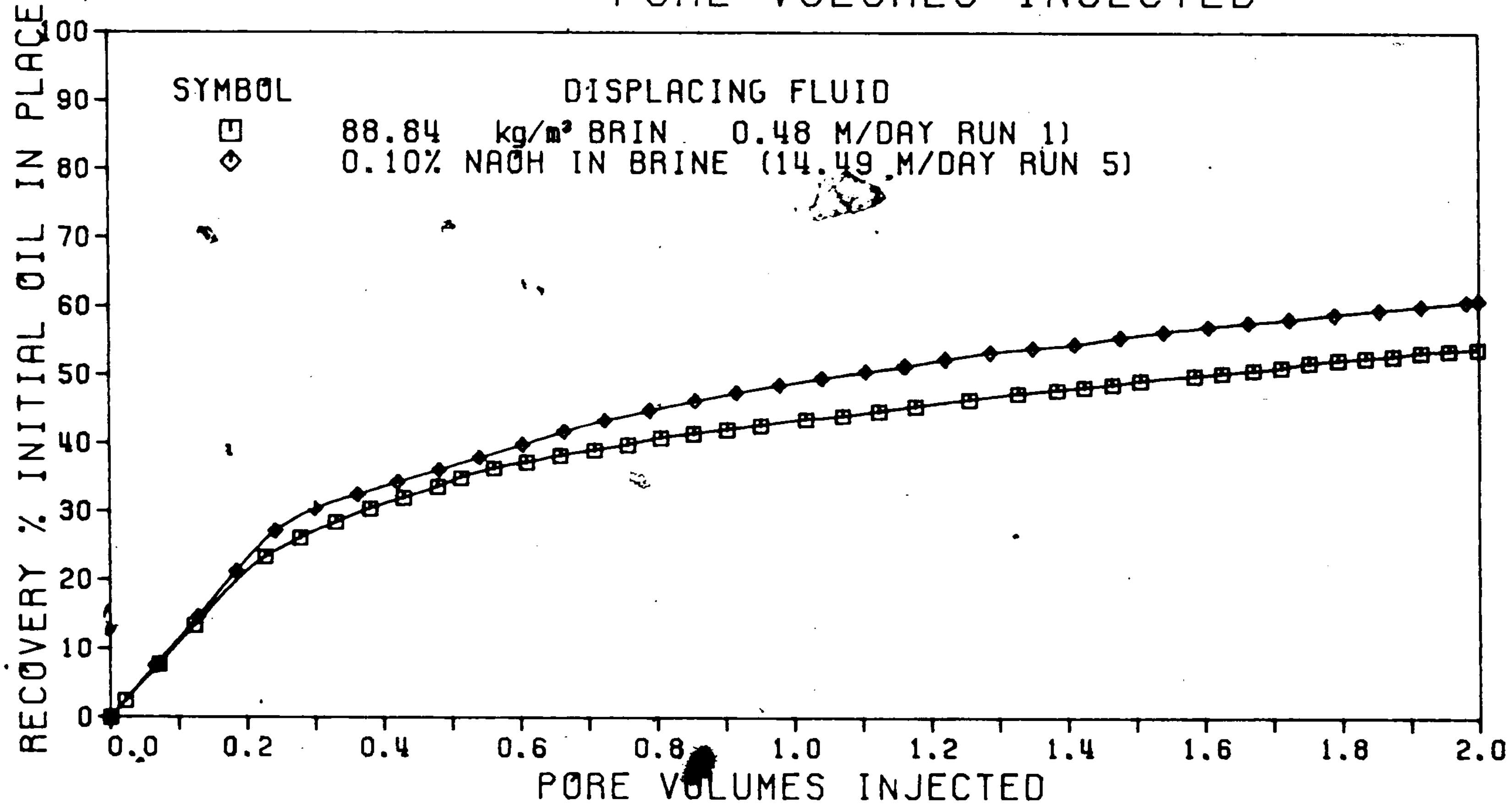

FIG C.14 : PRESSURE AND OIL CUT HISTORIES FOR RUN 5

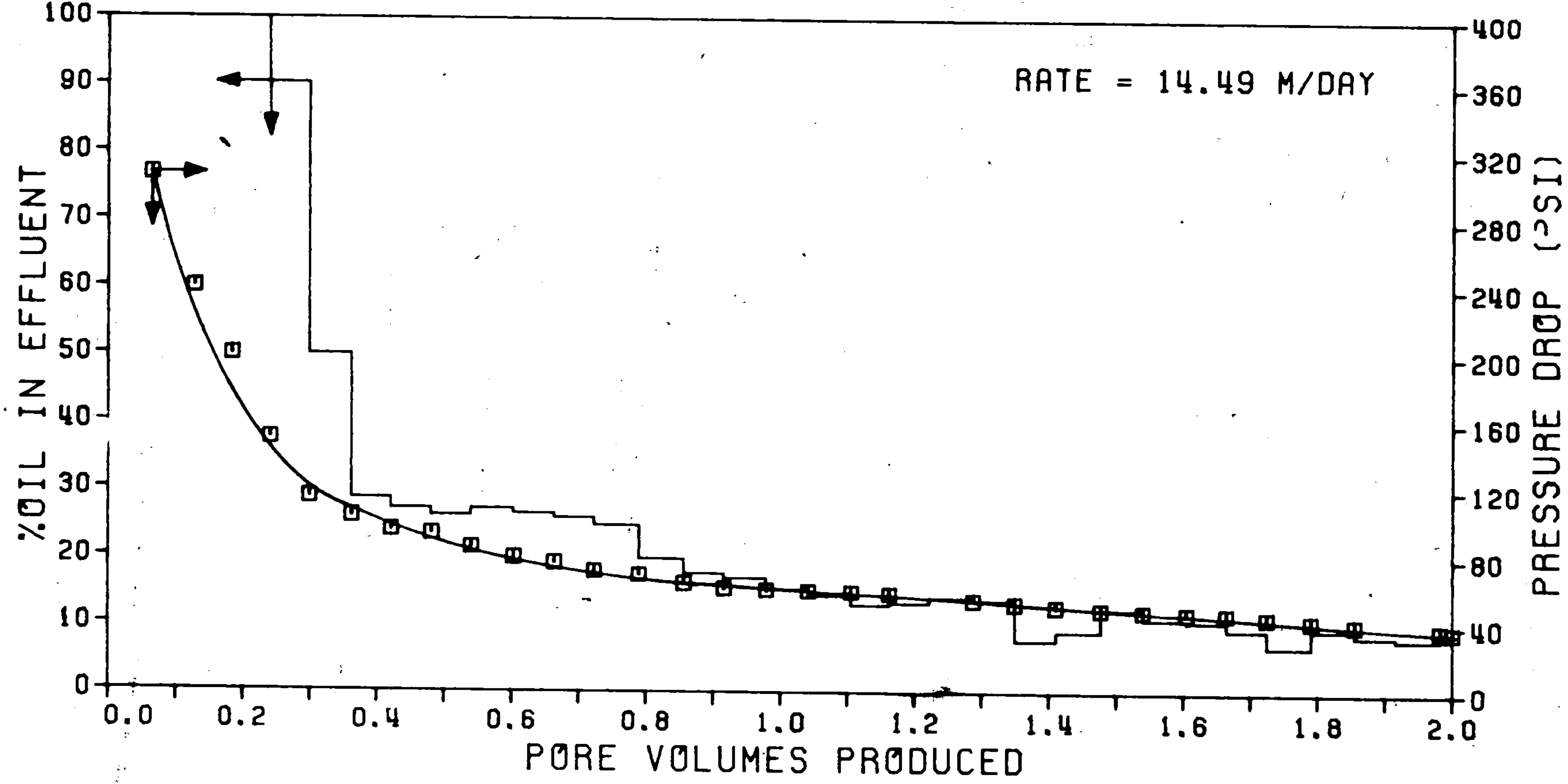

FIG C.15 : RELATIVE PERMEABILITY RATIO RUN 5

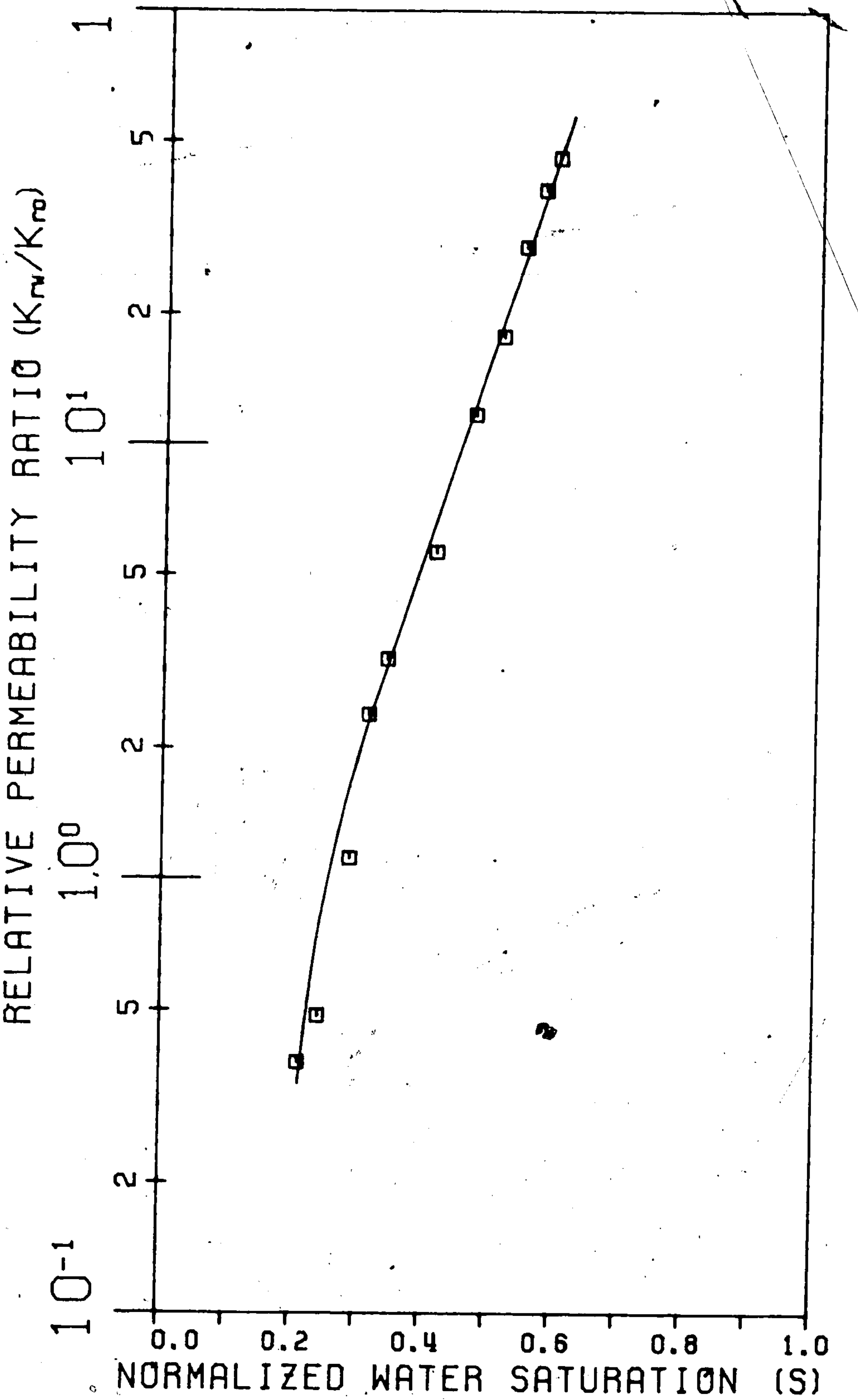

TABLE C- 6

CORE 3

RUN 6

CORE PROPERTIES

POROSITY = 36.0 %
PERMEABILITY = 22.4 D
PORE VOLUME = 810.9 ML
INITIAL WATER SAT. = 117.9 ML
INITIAL OIL IN PLACE = 693.0 ML

EXPERIMENTAL VARIABLES

RATE OF INJECTION = 12.5 ML/HR
CONCENTRATION NAOH = 0.10 WT-%
LINEAR RATE = 0.15 M/DAY

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
0.052	42.5	42.5	6.13	0.0	0.0	0.0	100.0			
0.106	43.5	86.0	12.41	0.0	0.0	0.0	100.0			
0.158	42.5	128.5	18.54	0.0	0.0	0.0	100.0			
0.211	42.5	171.0	24.68	0.0	0.0	0.0	100.0			
0.263	42.0	213.0	30.74	0.0	0.0	0.0	100.0			
0.314	39.0	252.0	36.36	3.0	3.0	0.1	92.9	6.40	0.00054	
0.367	29.5	281.5	40.62	13.5	16.5	0.5	68.6	6.79	0.00065	
0.422	21.0	302.5	43.65	23.0	39.5	1.1	47.7	6.95	0.00070	
0.478	22.0	324.5	46.83	23.5	63.0	1.1	48.4	7.13	0.00073	
0.530	22.0	346.5	50.00	20.5	83.5	0.9	51.8	7.22	0.00075	
0.583	21.5	368.0	53.10	21.0	104.5	1.0	50.6	8.89	0.00126	
0.635	15.5	383.5	55.34	27.0	131.5	1.7	36.5	10.30	0.00285	
0.687	8.5	392.0	56.57	33.5	165.0	3.9	20.2	11.34	0.01247	
0.738	4.0	396.0	57.14	37.5	202.5	9.4	9.6	11.60	0.02000	
0.792	1.5	397.5	57.36	42.5	245.0	28.3	3.4	11.64	0.02300	
0.907	2.0	399.5	57.65	91.0	336.0	45.5	2.2	11.72	0.02700	
0.959	2.0	401.5	57.94	40.0	376.0	20.0	4.8	11.82	0.03400	
1.060	2.0	403.5	58.23	80.0	456.0	40.0	2.4			
1.167	2.0	405.5	58.51	85.0	541.0	42.5	2.3	11.86	0.03850	
1.219	1.0	406.5	58.66	41.0	582.0	41.0	2.4			
1.278	2.0	408.5	58.95	46.0	628.0	23.0	4.2	11.90	0.04300	
1.382	2.0	410.5	59.24	82.0	710.0	41.0	2.4			
1.434	2.0	412.5	59.52	40.5	750.5	20.3	4.7			
1.487	1.5	414.0	59.74	41.0	791.5	27.3	3.5			
1.591	2.5	416.5	60.10	82.5	874.0	33.0	2.9	11.96	0.05100	
1.643	1.0	417.5	60.25	41.0	915.0	41.0	2.4			
1.701	1.5	419.0	60.46	45.5	960.5	30.3	3.2			

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TABLE C- 6 CONTINUED

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
1.754	1.5	420.5	60.68	41.5	1002.0	27.7	3.5	11.97	0.05300	
1.807	1.0	421.5	60.82	41.5	1043.5	41.5	2.4			
1.859	1.0	422.5	60.97	41.5	1085.0	41.5	2.4			
1.912	1.5	424.0	61.18	41.5	1126.5	27.7	3.5			
1.964	1.0	425.0	61.33	41.5	1168.0	41.5	2.4			
2.000	0.4	425.4	61.39	28.4	1196.4	71.0	1.4			

FIG C.16 : RECOVERY AS A FUNCTION OF PORE VOLUMES INJECTED

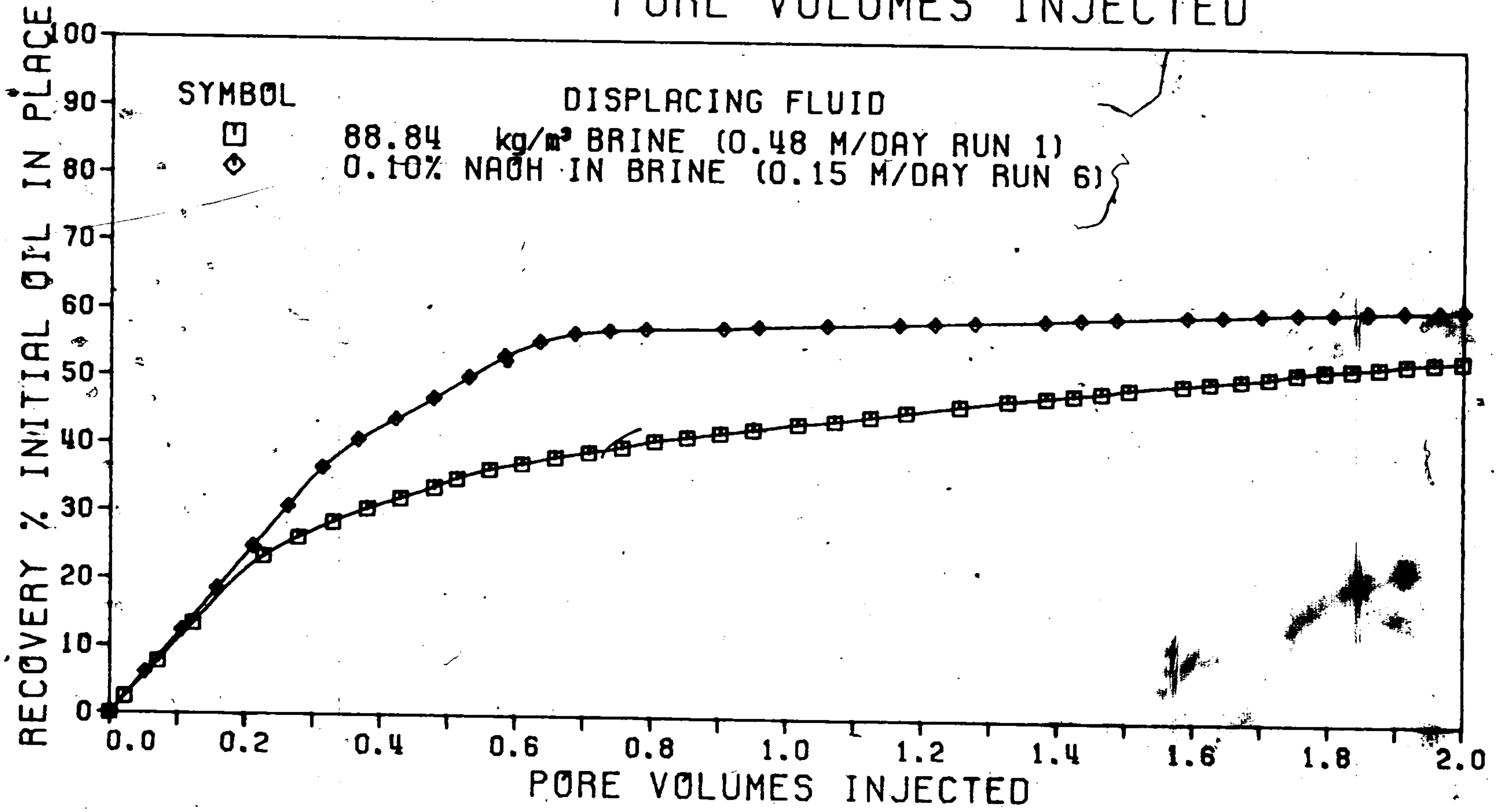

FIG C.17 : OIL CUT HISTORY FOR RUN 6

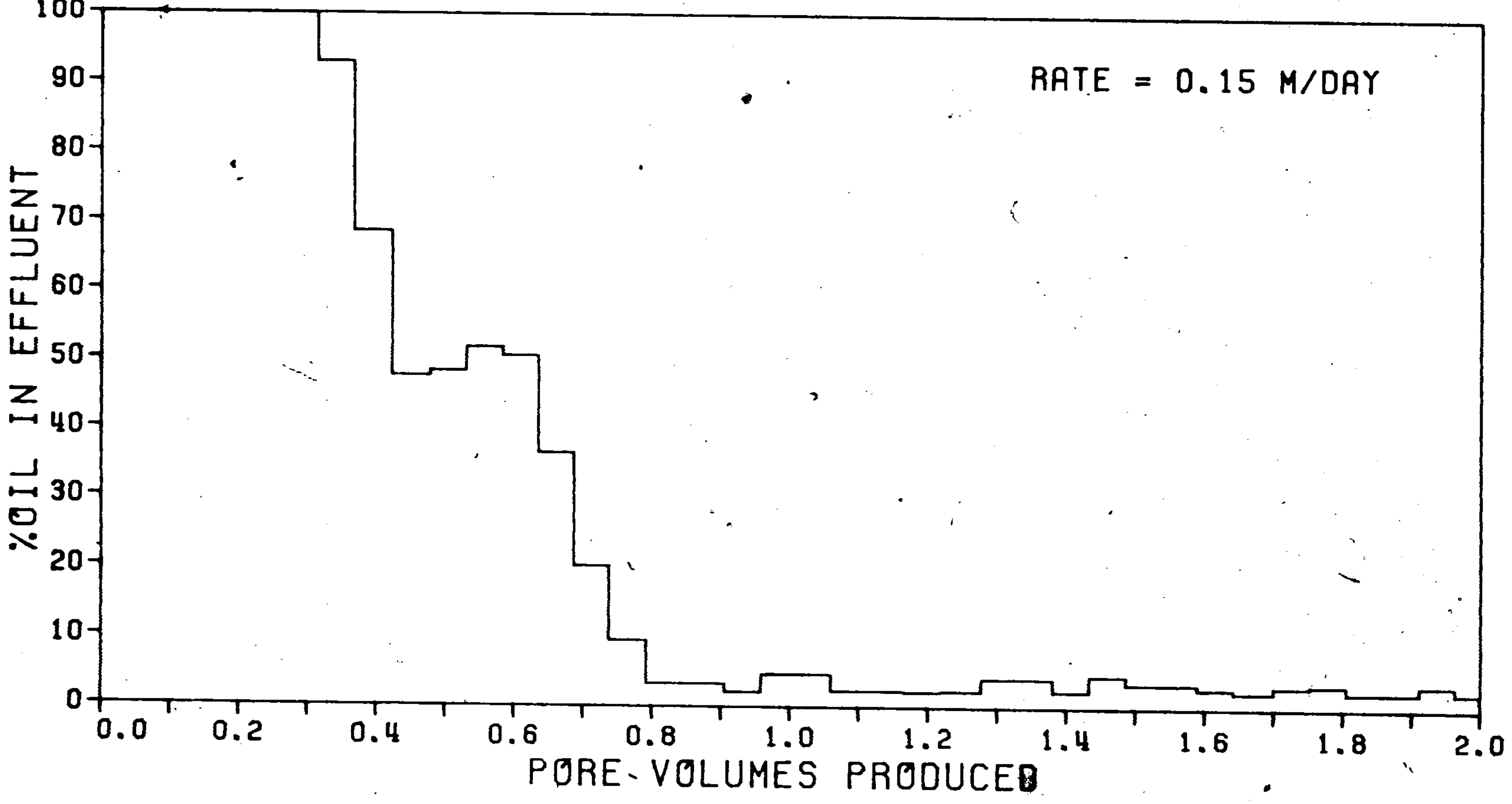

FIG C.18 : RELATIVE PERMEABILITY RATIO RUN 6

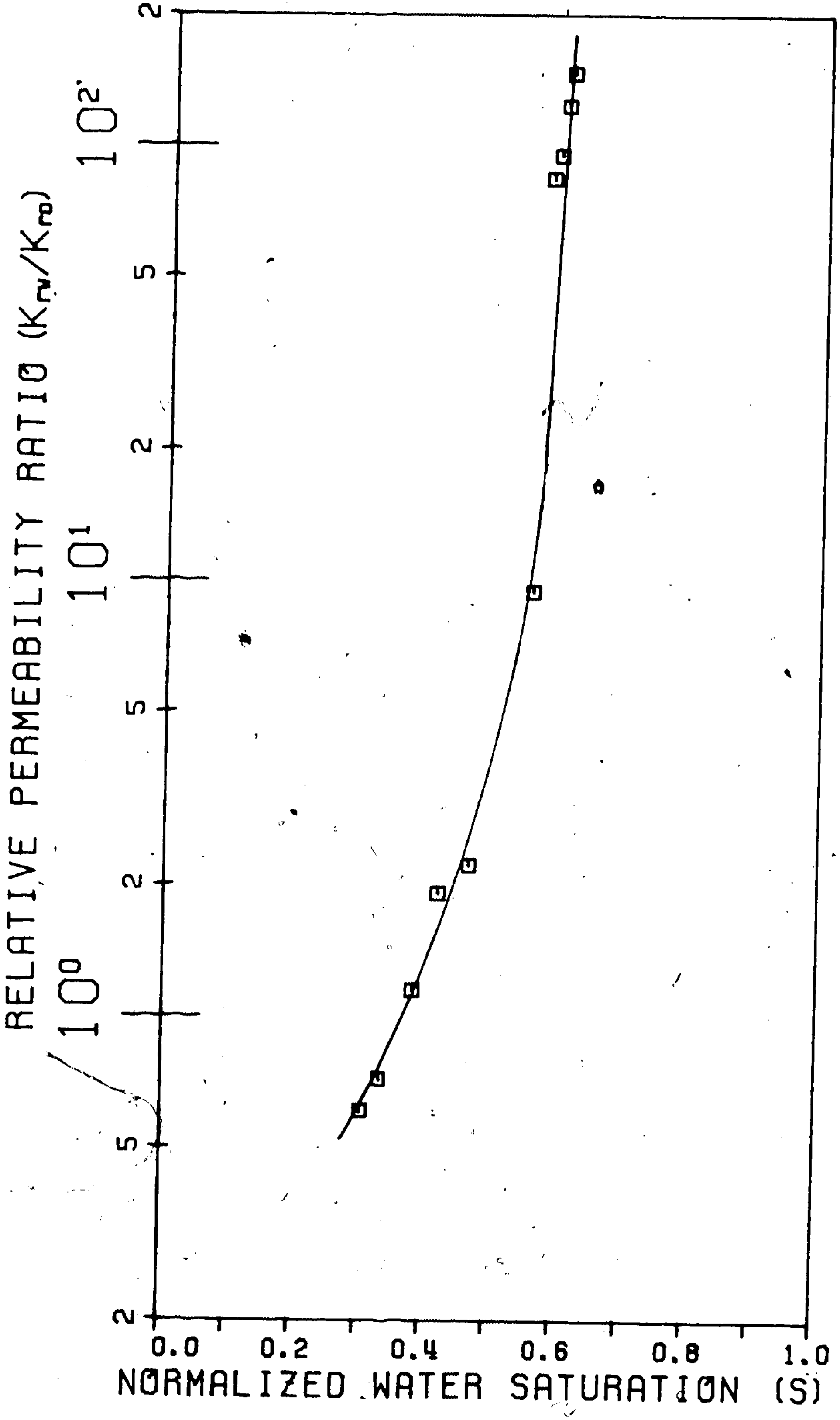

TABLE C- 7

CORE 2

RUN 7

CORE PROPERTIES

POROSITY = 33.2 %
PERMEABILITY = 19.9 D
PORE VOLUME = 695.5 ML
INITIAL WATER SAT. = 76.9 ML
INITIAL OIL IN PLACE = 618.6 ML

EXPERIMENTAL VARIABLES

RATE OF INJECTION = 250.0 ML/HR
CONCENTRATION NAOH = 0.10 WT-%
LINEAR RATE = 3.01 M/DAY

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
0.019	13.0	13.0	2.10	0.0	0.0	0.0	100.0			
0.078	41.0	54.0	8.73	0.0	0.0	0.0	100.0			
0.142	45.0	99.0	16.00	0.0	0.0	0.0	100.0			93.4
0.207	45.0	144.0	23.28	0.0	0.0	0.0	100.0			82.0
0.272	45.0	189.0	30.55	0.0	0.0	0.0	100.0			68.8
0.336	44.5	233.5	37.75	0.5	0.5	0.0	98.9			57.9
0.405	38.0	271.5	43.89	10.0	10.5	0.3	79.2	9.76	0.00192	43.9
0.469	18.0	289.5	46.80	26.0	36.5	1.4	40.9	11.36	0.01280	38.3
0.534	12.5	302.0	48.82	33.0	69.5	2.6	27.5			32.8
0.597	12.0	314.0	50.76	32.0	101.5	2.7	27.3	11.47	0.01530	29.9
0.661	14.0	328.0	53.02	30.0	131.5	2.1	31.8			26.3
0.725	9.5	337.5	54.56	35.0	166.5	3.7	21.3	11.57	0.01850	24.4
0.788	7.0	344.5	55.69	37.0	203.5	5.3	15.9	11.68	0.02400	
0.851	4.0	348.5	56.34	40.0	243.5	10.0	9.1	11.70	0.02500	22.2
0.914	3.5	352.0	56.90	40.0	283.5	11.4	8.0			
0.977	5.0	357.0	57.71	39.0	322.5	7.8	11.4	11.77	0.02930	19.8
1.042	5.0	362.0	58.52	40.0	362.5	8.0	11.1	11.79	0.03150	
1.106	4.0	366.0	59.17	40.5	403.0	10.1	9.0			17.8
1.169	3.0	369.0	59.65	41.0	444.0	13.7	6.8			
1.232	3.5	372.5	60.22	40.5	484.[illegible]	11.6	8.0	11.91	0.04100	16.1
1.296	1.5	374.0	60.46	43.0	527.5	28.7	3.4			
1.361	2.0	376.0	60.78	43.0	570.5	21.5	4.4			15.2
1.423	2.5	378.5	61.19	41.0	611.5	16.4	5.7			
1.487	2.0	380.5	61.51	42.5	654.0	21.3	4.5	11.96	0.05100	
1.551	2.0	382.5	61.83	42.0	696.0	21.0	4.5			14.6
1.613	1.5	384.0	62.08	42.0	738.0	28.0	3.4	11.95	0.05000	
1.676	1.5	385.5	62.32	42.0	780.0	28.0	3.4	11.95	0.05000	

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TABLE C- 7 CONTINUED

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
1.739	1.5	387.0	62.56	42.5	822.5	28.3	3.4	12.02	0.06500	
1.802	0.5	387.5	62.64	43.0	865.5	86.0	1.1			14.2
1.865	1.5	389.0	62.88	42.5	908.0	28.3	3.4			
1.927	1.5	390.5	63.13	41.5	949.5	27.7	3.5			
1.988	1.5	392.0	63.37	41.5	991.0	27.7	3.5	12.03	0.06700	

FIG C.19 : RECOVERY AS A FUNCTION OF PORE VOLUMES INJECTED

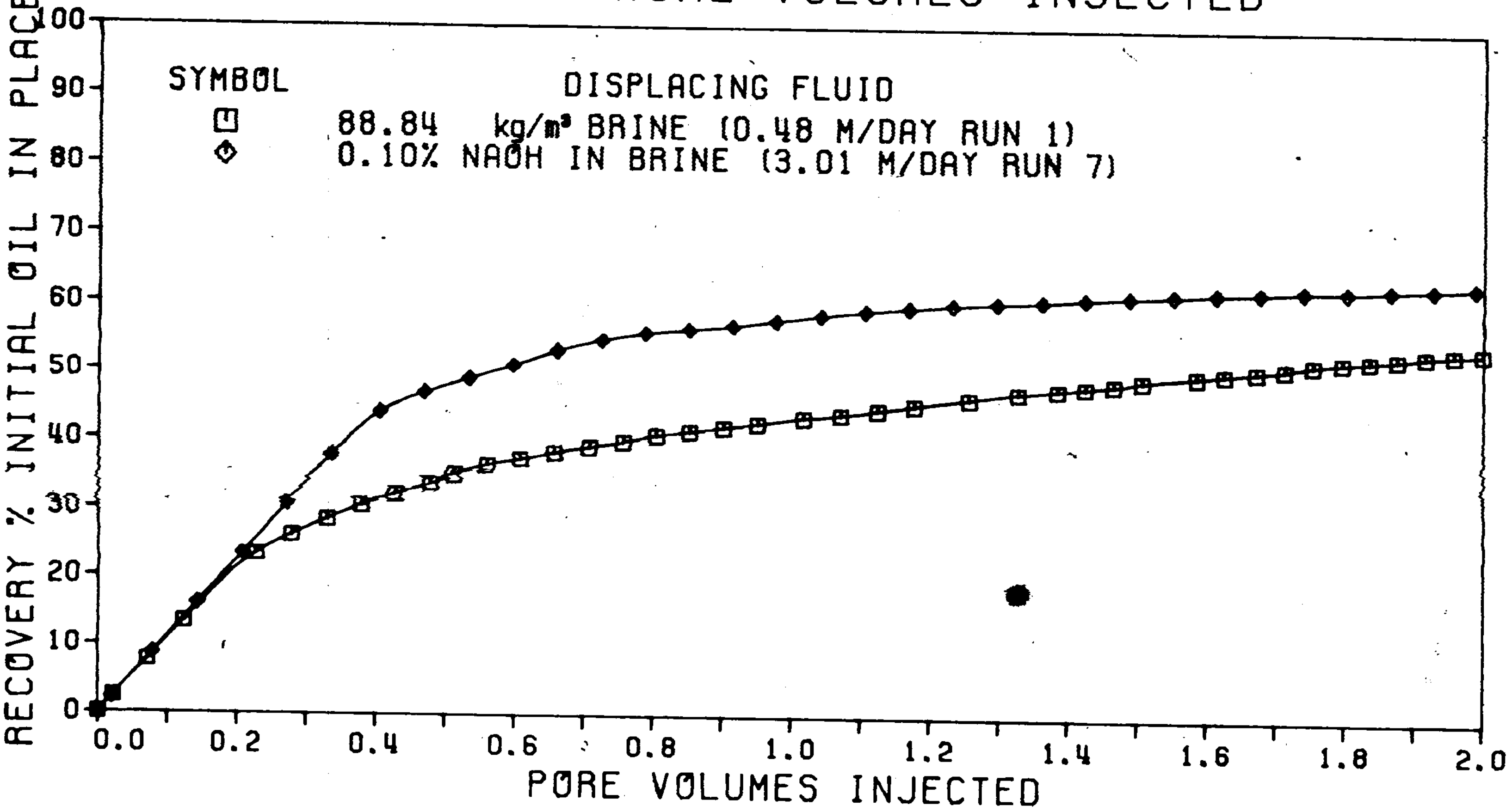

FIG C.20 : PRESSURE AND OIL CUT HISTORIES FOR RUN 7

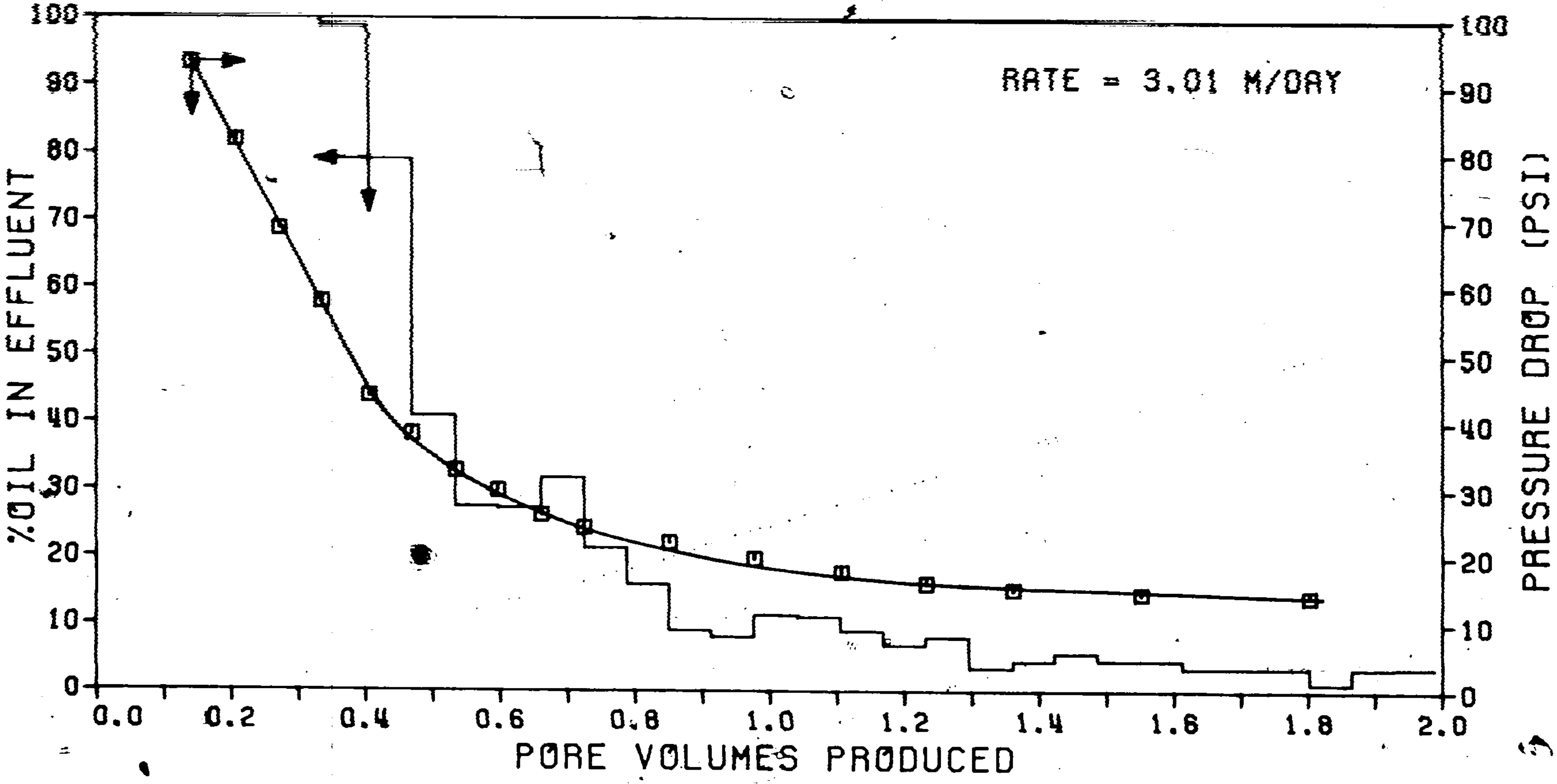

FIG C.21 : RELATIVE PERMEABILITY RATIO RUN 7

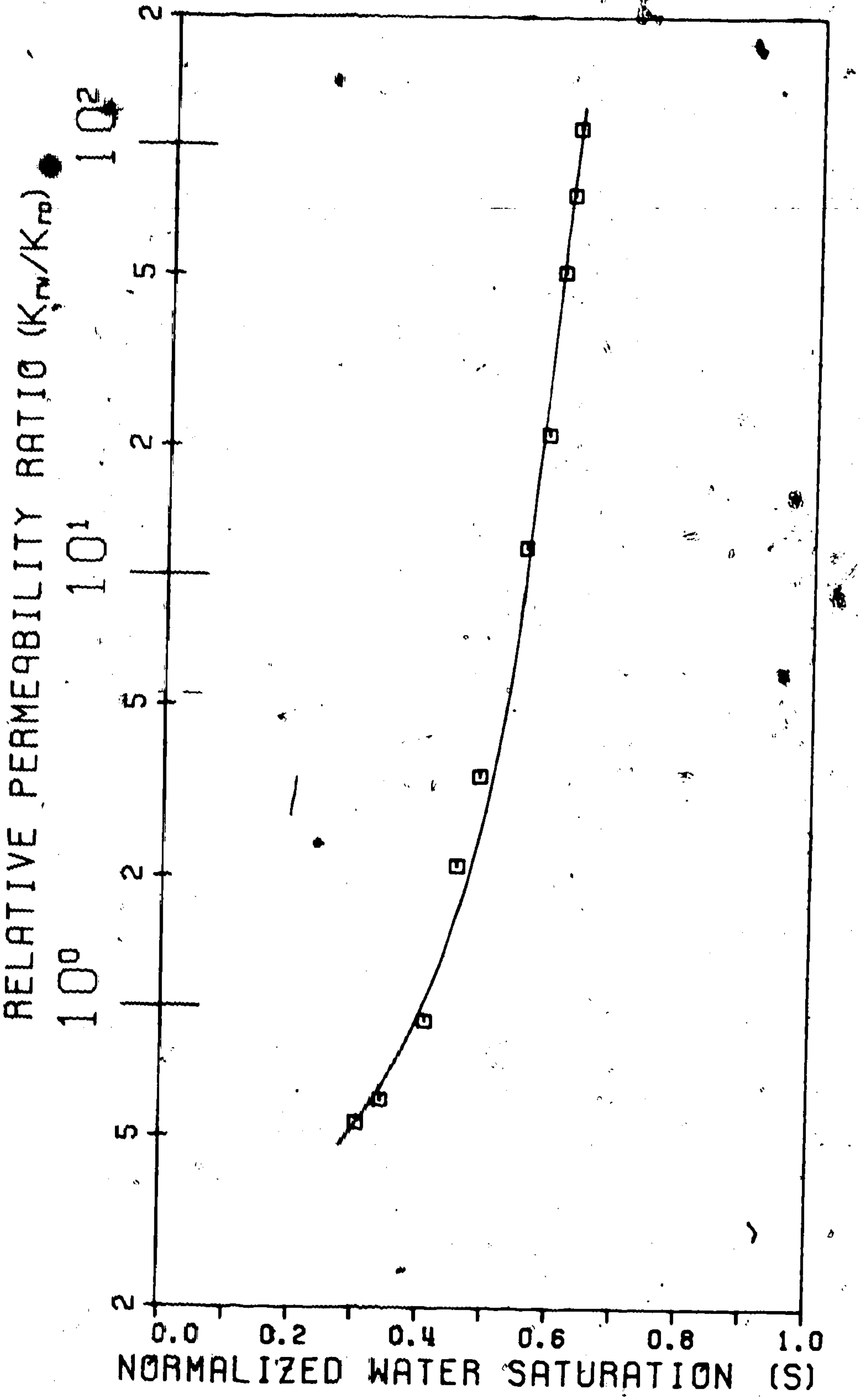

TABLE C- 8

CORE 4

RUN 8

CORE PROPERTIES

POROSITY = 34.4 %
PERMEABILITY = 18.1 D
PORE VOLUME = 722.6 ML
INITIAL WATER SAT. = 72.9 ML
INITIAL OIL IN PLACE = 649.7 ML

EXPERIMENTAL VARIABLES

RATE OF INJECTION = 250.0 ML/HR
CONCENTRATION NAOH = 0.01 WT-%
LINEAR RATE = 3.01 M/DAY

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
0.015	10.5	10.5	1.62	0.0	0.0	0.0	100.0			
0.073	42.0	52.5	8.08	0.0	0.0	0.0	100.0			93.0
0.135	45.0	97.5	15.01	0.0	0.0	0.0	100.0			81.9
0.195	43.5	141.0	21.70	0.0	0.0	0.0	100.0			70.1
0.256	36.0	177.0	27.24	8.0	8.0	0.2	81.8	6.61	0.00061	55.9
0.318	27.0	204.0	31.40	18.0	26.0	0.7	60.0			46.5
0.381	20.0	224.0	34.48	25.0	51.0	1.3	44.4	6.76	0.00065	41.8
0.444	17.5	241.5	37.17	28.5	79.5	1.6	38.0	7.17	0.00074	38.4
0.506	17.5	259.0	39.86	27.0	106.5	1.5	39.3	7.23	0.00075	
0.567	14.0	273.0	42.02	30.0	136.5	2.1	31.8	7.29	0.00076	33.9
0.629	15.0	288.0	44.33	30.0	166.5	2.0	33.3	7.38	0.00078	
0.690	13.5	301.5	46.41	30.5	197.0	2.3	30.7			31.0
0.750	13.0	314.5	48.41	30.5	227.5	2.3	29.9	7.39	0.00078	
0.810	13.5	328.0	50.48	30.0	257.5	2.2	31.0	7.38	0.00078	
0.871	12.0	340.0	52.33	32.0	289.5	2.7	27.3	7.37	0.00077	26.5
0.932	14.0	354.0	54.49	30.0	319.5	2.1	31.8	7.41	0.00079	
0.993	13.5	367.5	56.56	30.5	350.0	2.3	30.7	7.43	0.00079	
1.054	11.5	379.0	58.33	32.5	382.5	2.8	26.1			21.3
1.115	13.5	392.5	60.41	30.5	413.0	2.3	30.7	7.46	0.00079	
1.176	11.5	404.0	62.18	32.5	445.5	2.8	26.1			
1.237	10.0	414.0	63.72	34.0	479.5	3.4	22.7	7.55	0.00082	17.6
1.297	11.5	425.5	65.49	32.0	511.5	2.8	26.4	7.63	0.00083	
1.357	9.0	434.5	66.88	34.5	546.0	3.8	20.7	7.67	0.00084	
1.418	11.5	446.0	68.65	33.0	579.0	2.9	25.8			13.9
1.479	8.0	454.0	69.88	36.0	615.0	4.5	18.2	7.85	0.00088	
1.542	8.0	462.0	71.11	37.0	652.0	4.6	17.8			
1.604	6.0	468.0	72.03	39.0	691.0	6.5	13.3	8.11	0.00095	

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TABLE C- 8 CONTINUED

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
1.666	3.5	471.5	72.57	41.5	732.5	11.9	7.8			10.5
1.726	2.0	473.5	72.88	41.5	774.0	20.8	4.6			
1.787	4.0	477.5	73.50	40.0	814.0	10.0	9.1	8.53	0.00110	
1.847	1.5	479.0	73.73	42.0	856.0	28.0	3.4			
1.907	3.0	482.0	74.19	40.0	896.0	13.3	7.0			
1.966	1.5	483.5	74.42	41.0	937.0	27.3	3.5	9.34	0.00155	8.5
2.006	0.5	484.0	74.50	28.5	965.5	57.0	1.7			

FIG C.22 : RECOVERY AS A FUNCTION OF PORE VOLUMES INJECTED

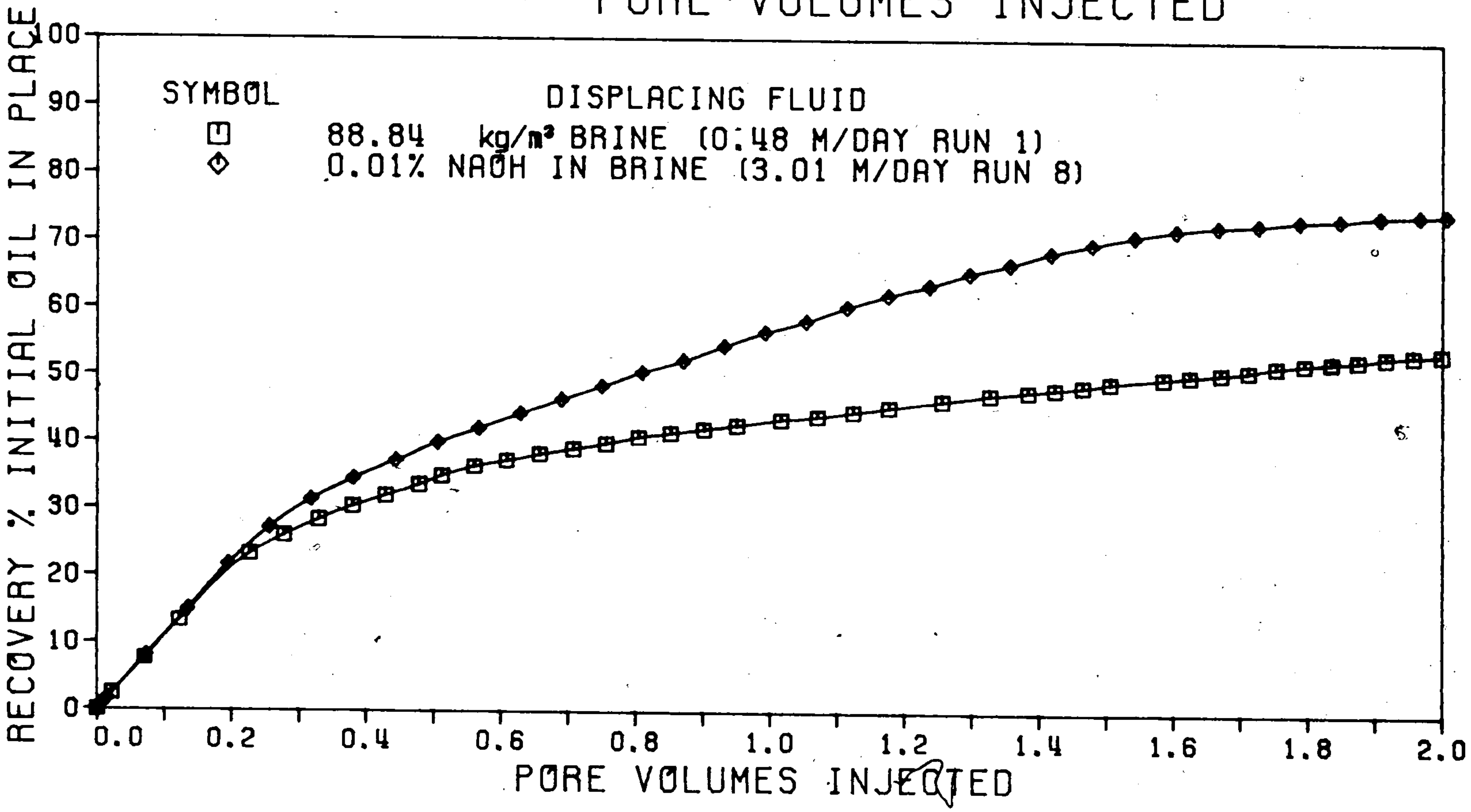

FIG C.23 : PRESSURE AND OIL CUT HISTORIES FOR RUN 8

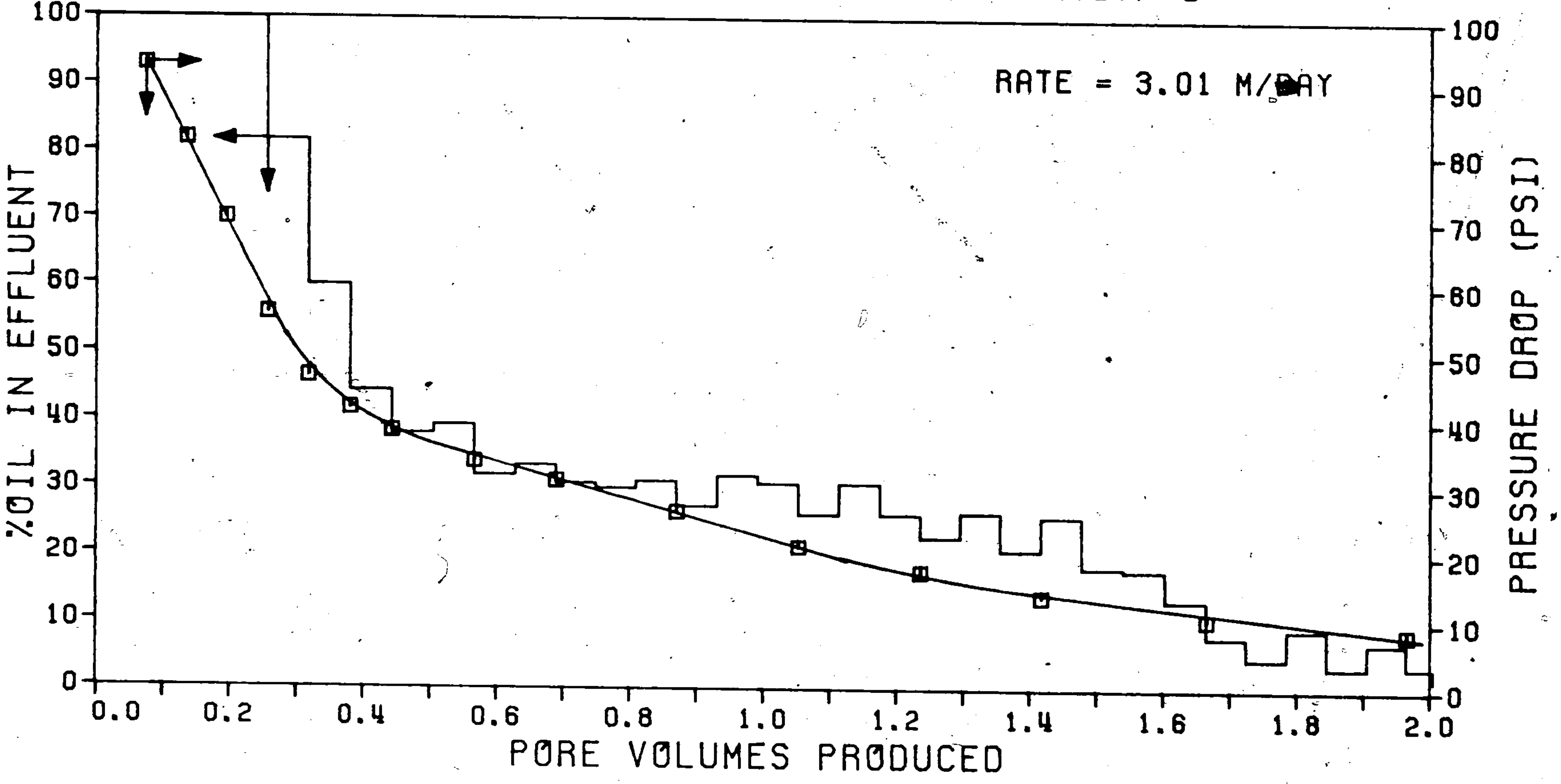

FIG C.24 : RELATIVE PERMEABILITY RATIO RUN 8

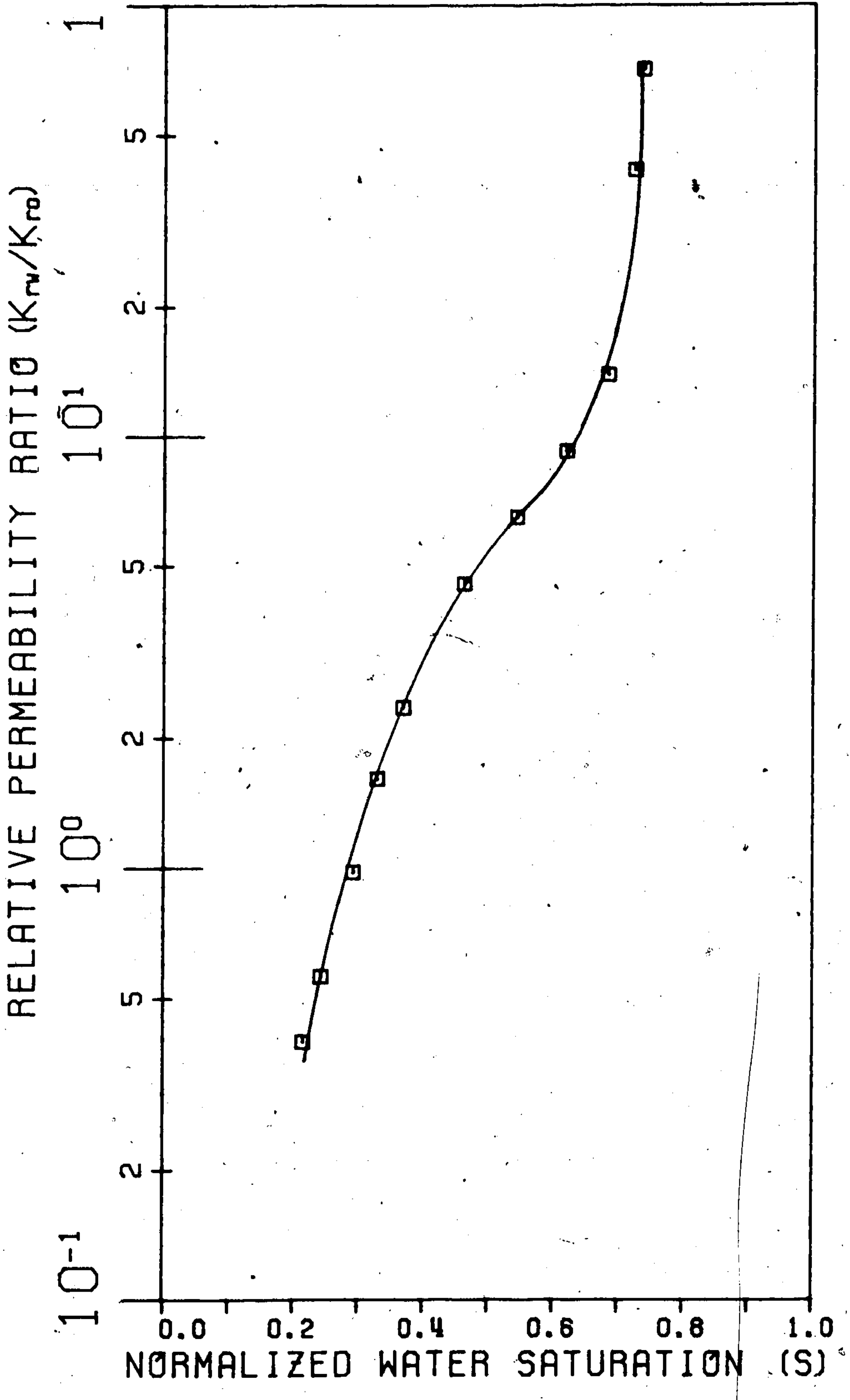

TABLE C- 9

CORE 3

RUN 9

CORE PROPERTIES
POROSITY = 35.9 %
PERMEABILITY = 20.1 D
PORE VOLUME = 809.9 ML
INITIAL WATER SAT. = 94.5 ML
INITIAL OIL IN PLACE = 715.4 ML

EXPERIMENTAL VARIABLES
RATE OF INJECTION = 250.0 ML/HR
CONCENTRATION NAOH = 2.00 WT-%
LINEAR RATE = 3.01 M/DAY

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
0.051	41.0	41.0	5.73	0.0	0.0	0.0	100.0			
0.104	43.5	84.5	11.81	0.0	0.0	0.0	100.0			93.8
0.159	44.0	128.5	17.96	0.0	0.0	0.0	100.0			80.1
0.214	44.5	173.0	24.18	0.0	0.0	0.0	100.0			66.1
0.269	45.0	218.0	30.47	0.0	0.0	0.0	100.0			51.8
0.325	20.0	238.0	33.27	25.0	25.0	1.3	44.4	13.31	0.00000	43.6
0.380	11.0	249.0	34.81	33.5	58.5	3.0	24.7	13.36	0.00000	39.9
0.434	9.0	258.0	36.06	35.0	93.5	3.9	20.5			36.6
0.489	10.0	268.0	37.46	34.5	128.0	3.4	22.5	13.36	0.00000	
0.543	10.0	278.0	38.86	34.0	162.0	3.4	22.7			31.3
0.597	7.0	285.0	39.84	36.5	198.5	5.2	16.1			
0.651	8.0	293.0	40.96	36.0	234.5	4.5	18.2	13.37	0.00000	28.5
0.706	7.0	300.0	41.93	37.5	272.0	5.4	15.7	13.37	0.00000	
0.760	6.0	306.0	42.77	37.5	309.5	6.3	13.8			
0.813	5.5	311.5	43.54	37.5	347.0	6.8	12.8			25.0
0.867	5.5	317.0	44.31	38.5	385.5	7.0	12.5			
0.921	6.0	323.0	45.15	37.7	423.2	6.3	13.7	13.31	0.00000	
0.976	7.0	330.0	46.13	37.0	460.2	5.3	15.9	13.39	0.00000	22.8
1.029	7.0	337.0	47.11	36.0	496.2	5.1	16.3			
1.087	8.0	345.0	48.22	39.0	535.2	4.9	17.0	13.35	0.00000	
1.140	8.0	353.0	49.34	35.0	570.2	4.4	18.6	13.25	0.00000	
1.194	3.5	356.5	49.83	40.0	610.2	11.4	8.0			19.3
1.245	2.5	359.0	50.18	39.5	649.7	15.8	6.0			
1.299	3.5	362.5	50.67	40.0	689.7	11.4	8.0	13.38	0.00000	
1.352	3.5	366.0	51.16	39.5	729.2	11.3	8.1			
1.407	2.0	368.0	51.44	42.0	771.2	21.0	4.5			17.9
1.460	2.5	370.5	51.79	41.0	812.2	16.4	5.7			

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TABLE C- 9 CONTINUED

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
1.515	2.5	373.0	52.14	41.5	853.7	16.6	5.7	13.45	0.00000	
1.570	3.5	376.5	52.63	41.0	894.7	11.7	7.9			
1.623	3.0	379.5	53.05	40.0	934.7	13.3	7.0			
1.676	2.5	382.0	53.40	41.0	975.7	16.4	5.7			15.9
1.729	2.5	384.5	53.75	40.0	1015.7	16.0	5.9	13.42	0.00000	
1.783	2.5	387.0	54.10	41.5	1057.2	16.6	5.7			
1.838	2.5	389.5	54.45	41.5	1098.7	16.6	5.7			
1.892	2.5	392.0	54.79	41.5	1140.2	16.6	5.7			
1.946	2.5	394.5	55.14	41.5	1181.7	16.6	5.7			14.8
2.000	2.0	396.5	55.42	41.5	1223.2	20.8	4.6	13.45	0.00000	

FIG C.25 : RECOVERY AS A FUNCTION OF PORE VOLUMES INJECTED

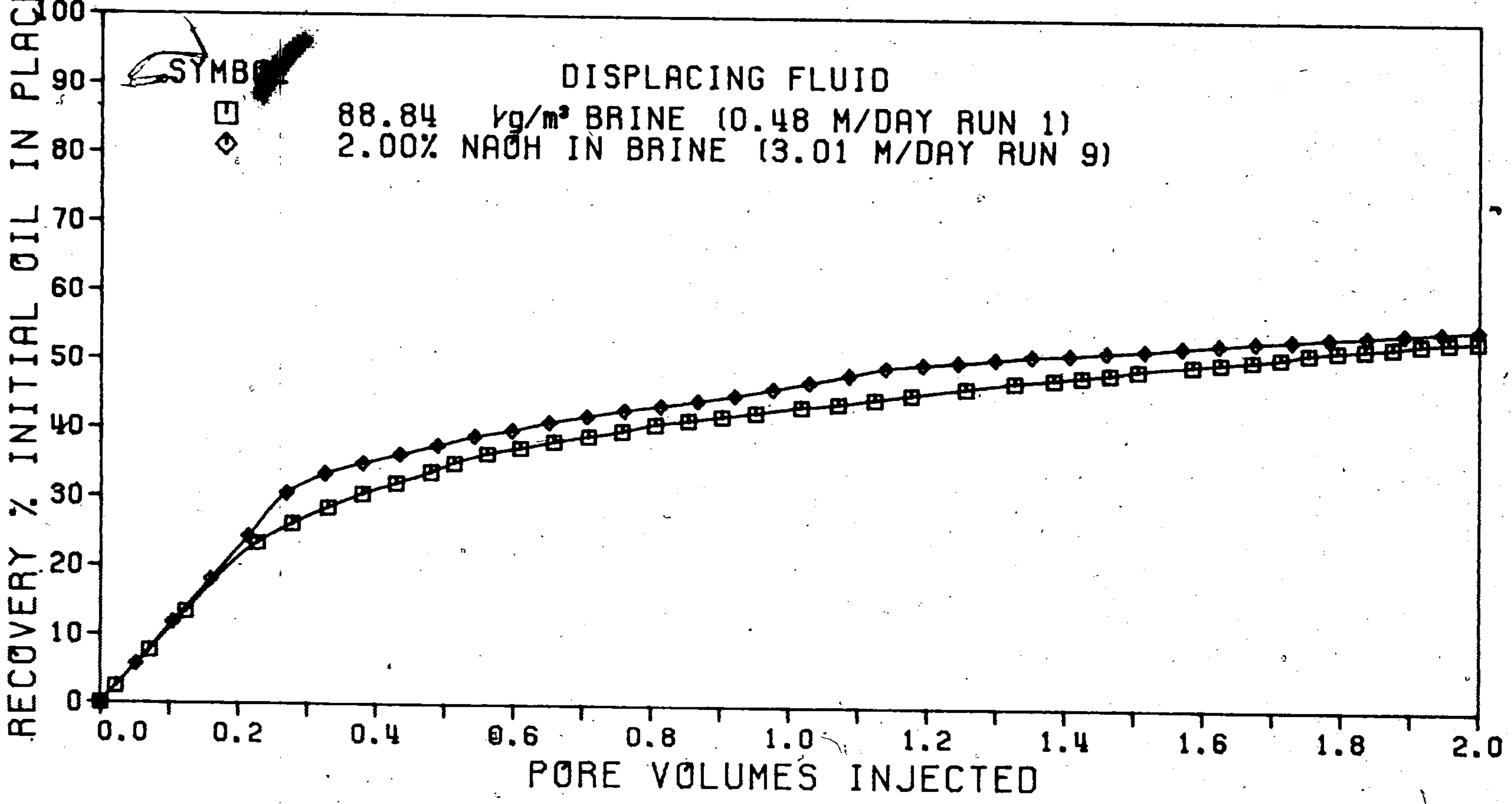

FIG C.26 : PRESSURE AND OIL CUT HISTORIES FOR RUN 9

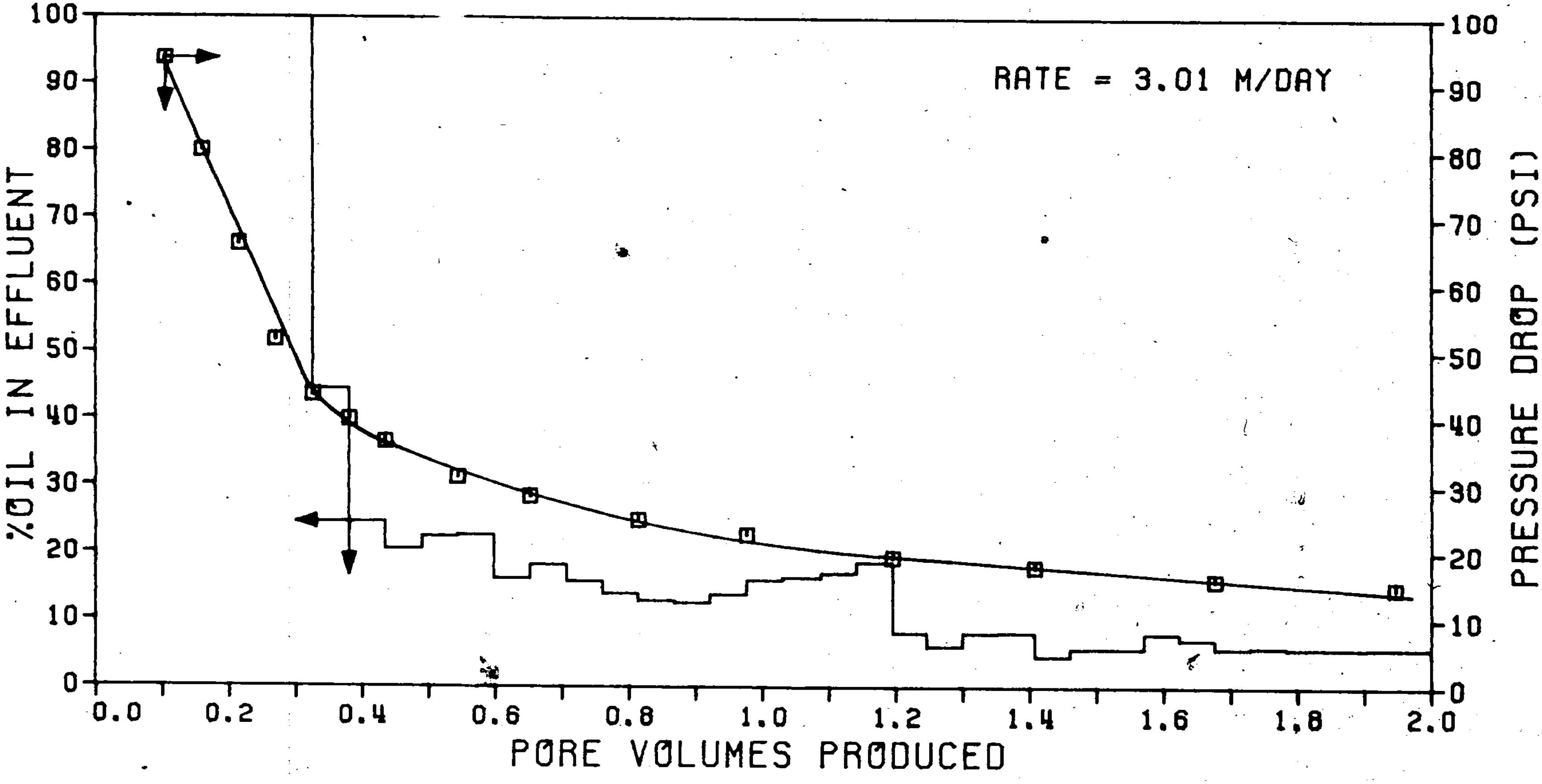

FIG C.27 : RELATIVE PERMEABILITY RATIO RUN 9

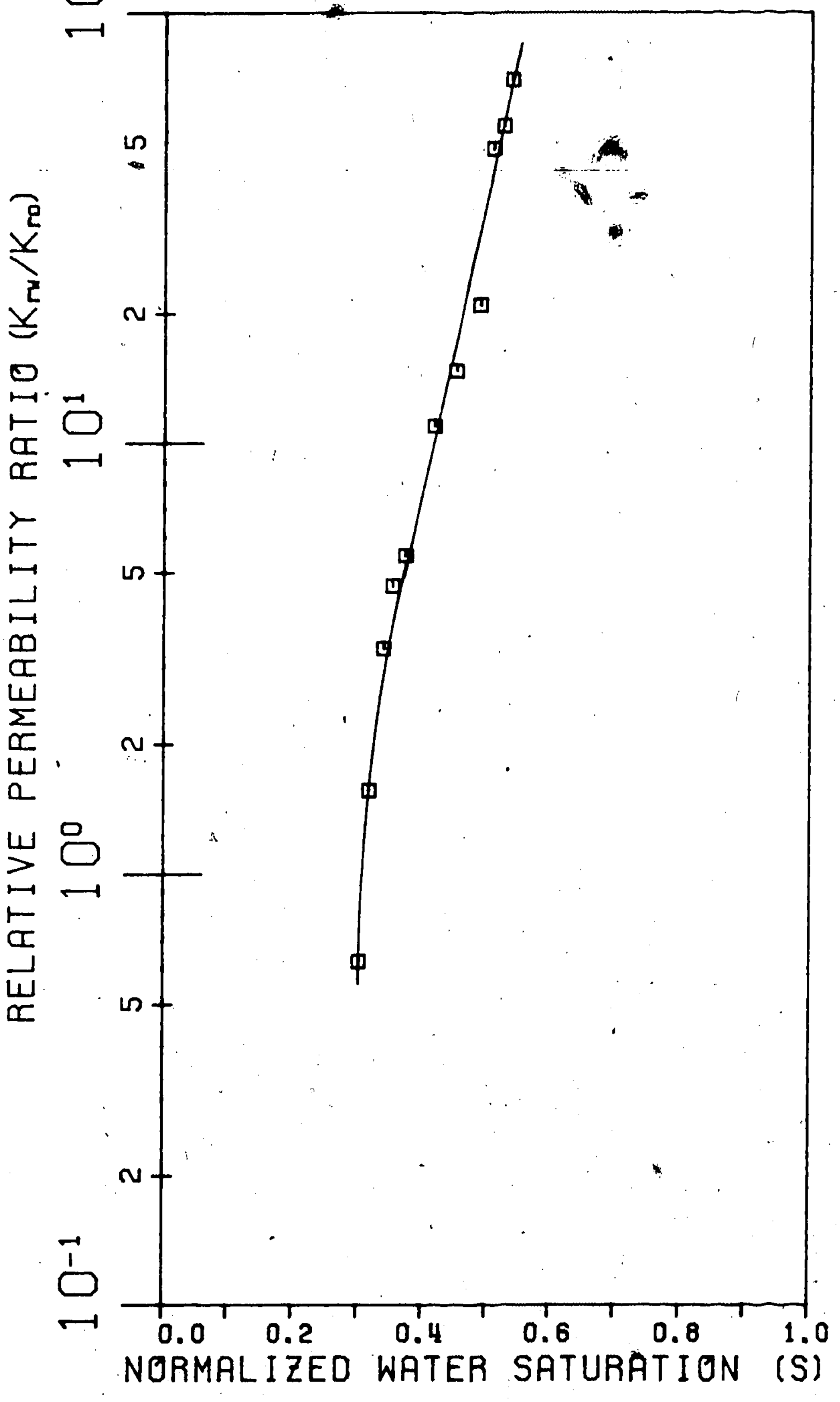

TABLE C-10

CORE 1

RUN 10

CORE PROPERTIES
FOROSITY = 34.3 %
PERMEABILITY = 19.4 D
PORE VOLUME = 718.4 ML
INITIAL WATER SAT. = 81.3 ML
INITIAL OIL IN PLACE = 637.1 ML

EXPERIMENTAL VARIABLES
RATE OF INJECTION = 40.0 ML/HR
CONCENTRATION NAOH = 0.01 WT-%
LINEAR RATE = 0.48 M/DAY

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
0.065	46.5	46.5	7.30	0.0	0.0	0.0	100.0			22.0
0.110	32.5	79.0	12.40	0.0	0.0	0.0	100.0			19.2
0.155	32.0	111.0	17.42	0.0	0.0	0.0	100.0			16.8
0.216	40.0	151.0	23.70	4.0	4.0	0.1	90.9	6.05	0.00042	14.2
0.277	33.5	184.5	28.96	10.5	14.5	0.3	76.1	6.32	0.00052	12.5
0.338	26.5	211.0	33.12	17.0	31.5	0.6	60.9			11.0
0.398	24.0	235.0	36.89	19.5	51.0	0.8	55.2	6.92	0.00069	9.8
0.459	21.0	256.0	40.18	22.5	73.5	1.1	48.3	7.04	0.00072	9.0
0.519	16.5	272.5	42.77	26.5	100.0	1.6	38.4			8.2
0.580	17.0	289.5	45.44	27.0	127.0	1.6	38.6			7.1
0.640	14.0	303.5	47.64	29.0	156.0	2.1	32.6	7.44	0.00079	
0.693	11.5	315.0	49.44	27.0	183.0	2.3	29.9			
0.757	11.0	326.0	51.17	34.5	217.5	3.1	24.2	7.98	0.00091	
0.817	8.5	334.5	52.50	35.0	252.5	4.1	19.5			
0.877	6.5	341.0	53.52	36.5	289.0	5.6	15.1	8.23	0.00099	5.0
0.937	6.0	347.0	54.47	37.0	326.0	6.2	14.0			
0.998	6.5	353.5	55.49	37.5	363.5	5.8	14.8	7.62	0.00083	
1.067	8.0	361.5	56.74	41.5	405.0	5.2	16.2			
1.135	7.5	369.0	57.92	41.5	446.5	5.5	15.3	8.22	0.00098	4.5
1.192	5.5	374.5	58.78	35.5	482.0	6.5	13.4	7.76	0.00086	
1.256	12.5	387.0	60.74	33.5	515.5	2.7	27.2			
1.320	9.0	396.0	62.16	37.0	552.5	4.1	19.6			
1.386	13.0	409.0	64.20	34.5	587.0	2.7	27.4	7.83	0.00087	
1.451	11.5	420.5	66.00	35.0	622.0	3.0	24.7	7.91	0.00089	
1.511	1.5	422.0	66.24	41.5	663.5	27.7	3.5	8.96	0.00130	
1.584	3.5	425.5	66.79	49.0	712.5	14.0	6.7	10.28	0.00280	
1.643	2.5	428.0	67.18	39.5	752.0	15.8	6.0	10.19	0.00260	

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TABLE C-10 CONTINUED

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
1.687	2.0	430.0	67.49	30.0	782.0	15.0	6.3			
1.747	1.5	431.5	67.73	41.5	823.5	27.7	3.5	10.22	0.00270	
1.794	1.5	433.0	67.96	32.0	855.5	21.3	4.5			
1.852	1.5	434.5	68.20	40.5	896.0	27.0	3.6			
1.910	1.5	436.0	68.44	40.0	936.0	26.7	3.6			
1.968	1.5	437.5	68.67	40.5	976.5	27.0	3.6	10.30	0.00285	
2.000	0.8	438.3	68.80	21.7	998.2	27.1	3.6			

FIG C.28 : RECOVERY AS A FUNCTION OF PORE VOLUMES INJECTED

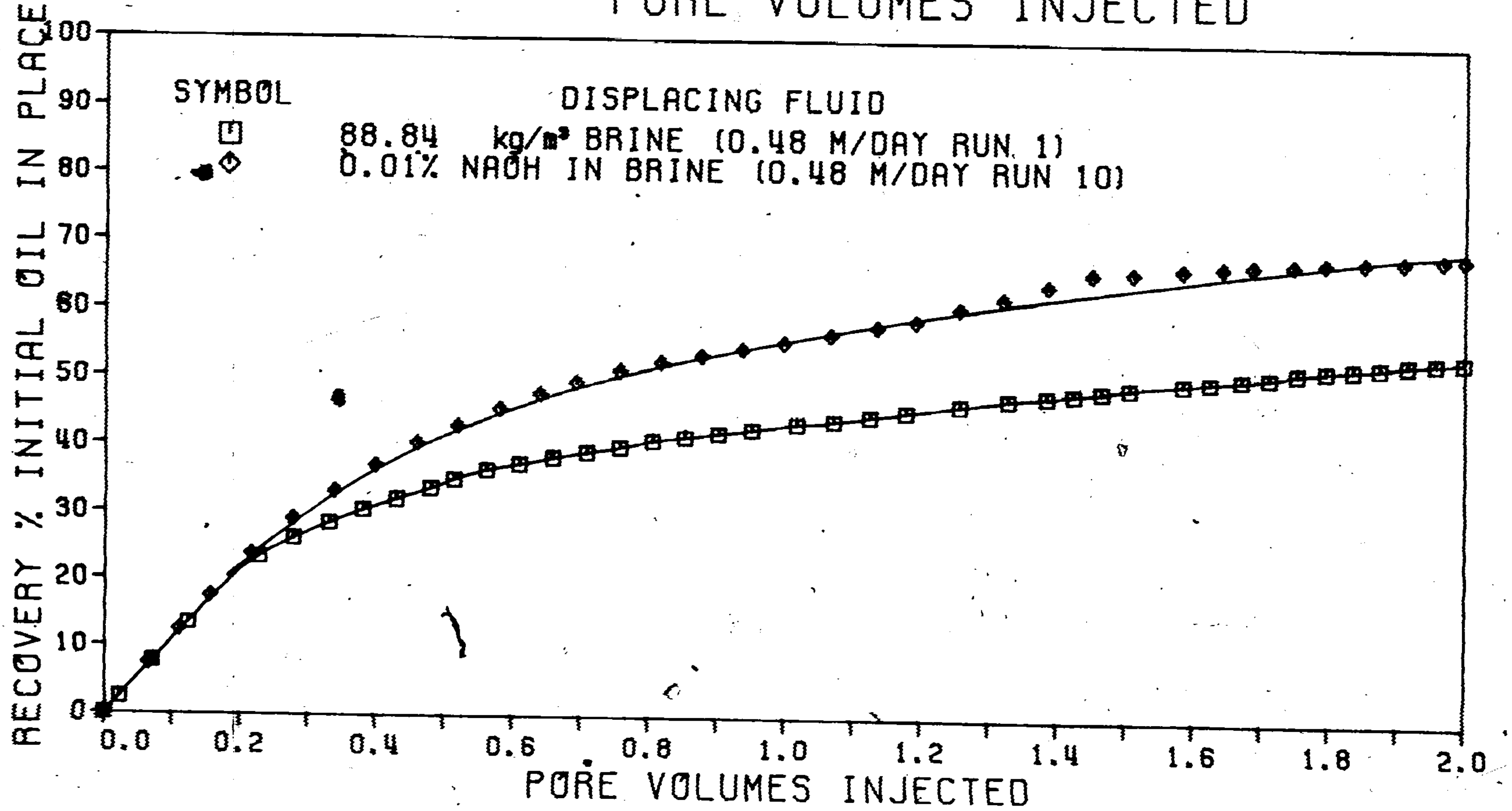

FIG C.29 : PRESSURE AND OIL CUT HISTORIES FOR RUN 10

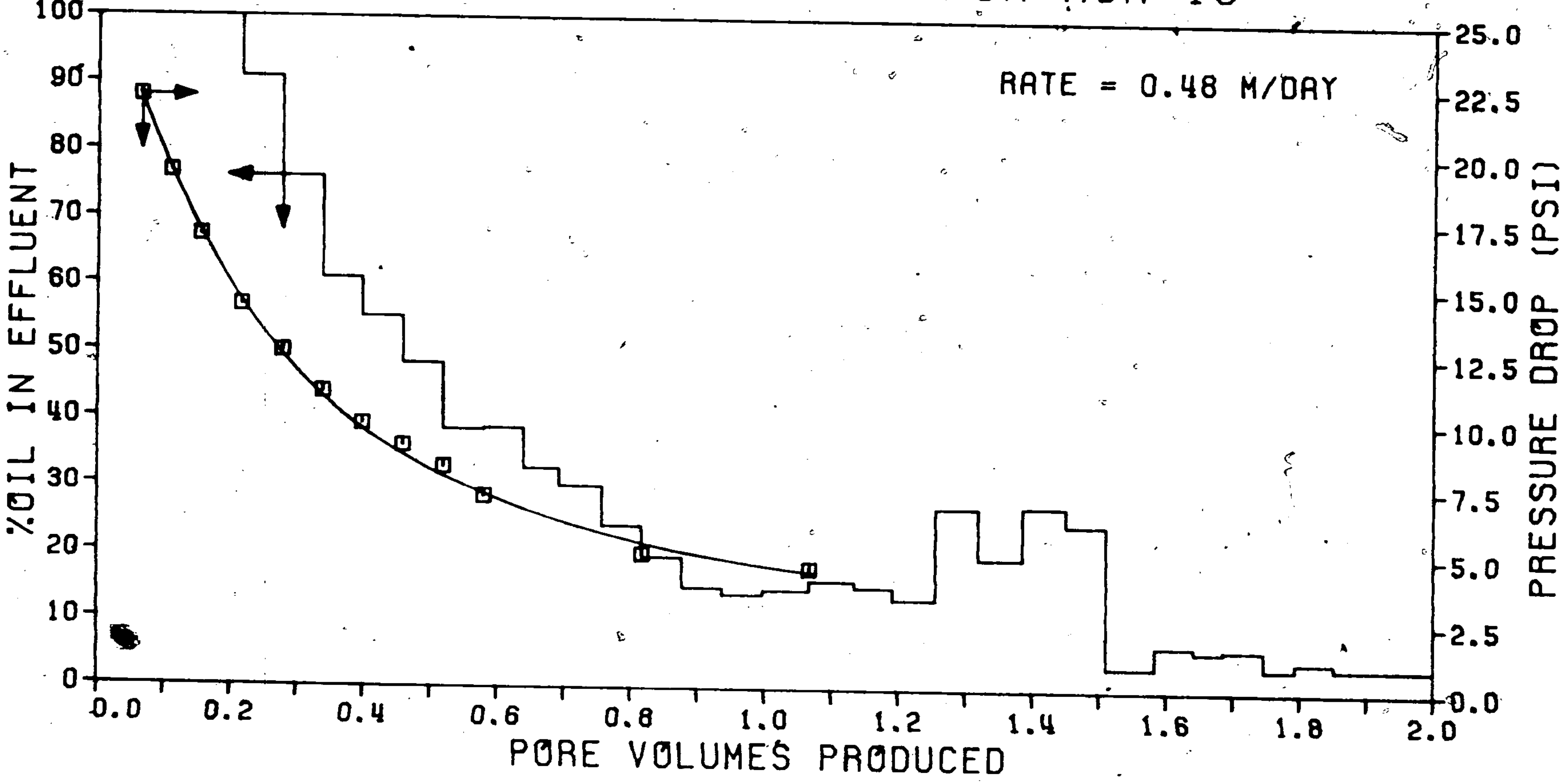

FIG C.30 : RELATIVE PERMEABILITY RATIO RUN 10

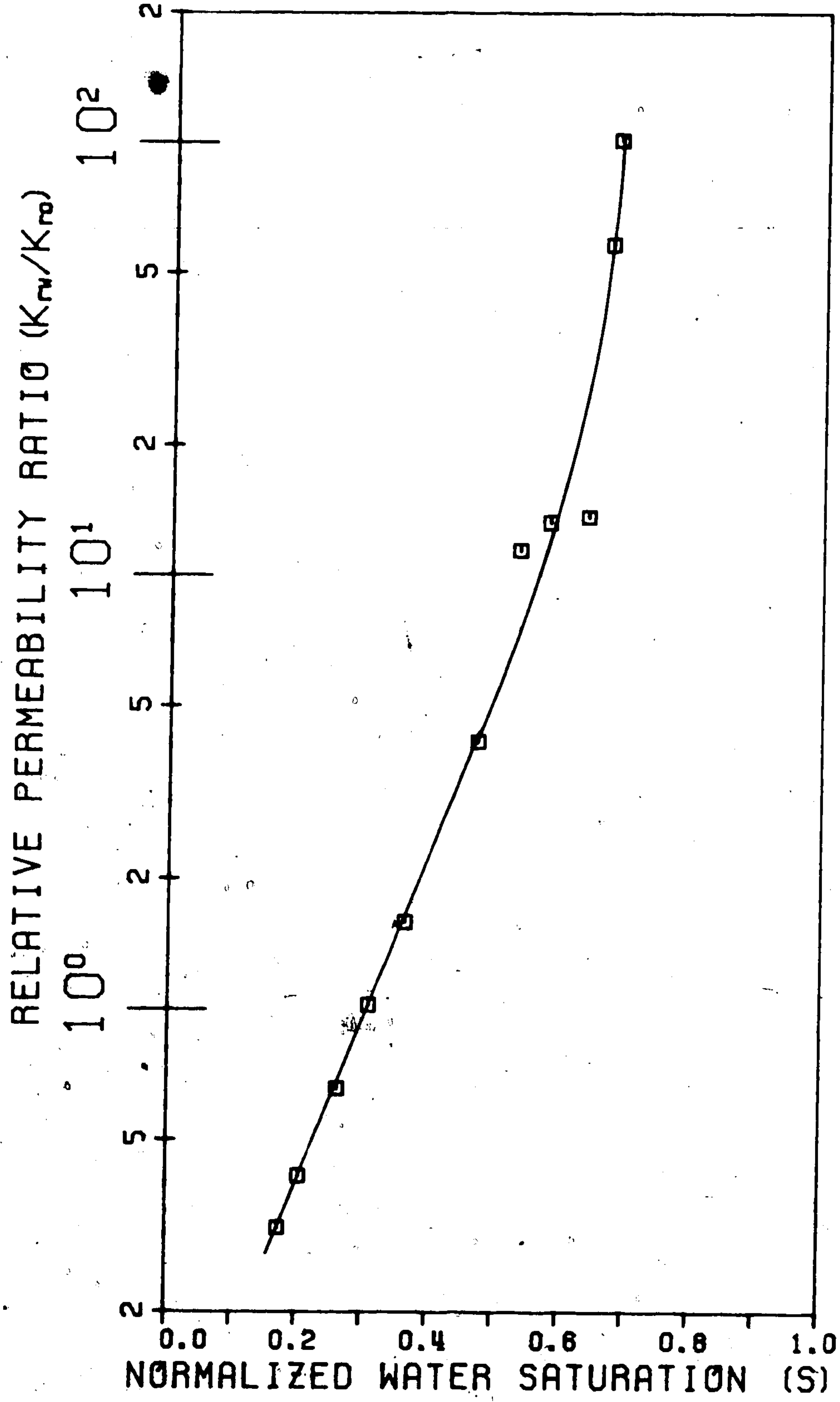

TABLE C-11

CORE 4

RUN 11

CORE PROPERTIES
POROSITY = 33.6 %
PERMEABILITY = 17.7 D
PORE VOLUME = 706.5 ML
INITIAL WATER SAT. = 74.1 ML
INITIAL OIL IN PLACE = 632.4 ML

EXPERIMENTAL VARIABLES
RATE OF INJECTION = 12.5 ML/HR
CONCENTRATION NAOH = 0.01 WT-%
LINEAR RATE = 0.15 M/DAY

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
0.052	37.0	37.0	5.85	0.0	0.0	0.0	100.0			
0.102	35.0	72.0	11.39	0.0	0.0	0.0	100.0			
0.171	38.5	110.5	17.47	10.0	10.0	0.3	79.4	6.62	0.00062	
0.208	11.5	122.0	19.29	15.0	25.0	1.3	43.4	6.85	0.00067	
0.246	11.5	133.5	21.11	15.0	40.0	1.3	43.4	6.91	0.00069	
0.285	11.5	145.0	22.93	16.0	56.0	1.4	41.8	7.03	0.00071	
0.322	9.5	154.5	24.43	17.0	73.0	1.8	35.8			
0.390	19.5	174.0	27.51	28.5	101.5	1.5	40.6	7.22	0.00075	
0.462	16.0	190.0	30.04	35.0	136.5	2.2	31.4			
0.531	15.0	205.0	32.42	33.5	170.0	2.2	30.9			
0.569	8.0	213.0	33.68	19.0	189.0	2.4	29.6	7.28	0.00076	
0.607	7.5	220.5	34.87	19.5	208.5	2.6	27.8			
0.665	11.0	231.5	36.61	30.0	238.5	2.7	26.8	7.33	0.00077	
0.742	12.0	243.5	38.50	42.0	280.5	3.5	22.2			
0.780	6.0	249.5	39.45	21.0	301.5	3.5	22.2			
0.843	9.5	259.0	40.96	35.0	336.5	3.7	21.3			
0.905	10.0	269.0	42.54	34.0	370.5	3.4	22.7	7.37	0.00077	
0.964	8.0	277.0	43.80	33.5	404.0	4.2	19.3	7.44	0.00079	
0.996	5.0	282.0	44.59	18.0	422.0	3.6	21.7	7.63	0.00083	
1.036	7.0	289.0	45.70	21.0	443.0	3.0	25.0	7.64	0.00083	
1.080	6.0	295.0	46.65	25.0	468.0	4.2	19.4	7.71	0.00085	
1.142	9.0	304.0	48.07	35.0	503.0	3.9	20.5			
1.206	7.5	311.5	49.26	37.5	540.5	5.0	16.7			
1.279	8.0	319.5	50.52	43.5	584.0	5.4	15.5	7.53	0.00081	
1.318	4.0	323.5	51.15	23.5	607.5	5.9	14.5	7.57	0.00082	
1.356	3.0	326.5	51.63	24.0	631.5	8.0	11.1	7.67	0.00084	
1.394	5.0	331.5	52.42	22.0	653.5	4.4	18.5	7.78	0.00086	

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TABLE C-11 CONTINUED

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
1.432	3.5	335.0	52.97	23.5	677.0	6.7	13.0	7.73	0.00085	
1.470	3.0	338.0	53.45	23.5	700.5	7.8	11.3	7.81	0.00087	
1.510	4.0	342.0	54.08	24.5	725.0	6.1	14.0	7.82	0.00087	
1.549	4.0	346.0	54.71	23.5	748.5	5.9	14.5	7.91	0.00089	
1.587	4.5	350.5	55.42	22.0	770.5	4.9	17.0	7.93	0.00090	
1.626	2.5	353.0	55.82	25.0	795.5	10.0	9.1	7.90	0.00087	
1.665	3.0	356.0	56.29	24.5	820.0	8.2	10.9			
1.729	6.5	362.5	57.32	39.0	859.0	6.0	14.3			
1.767	7.0	369.5	58.43	20.0	879.0	2.9	25.9			
1.834	6.5	376.0	59.46	40.5	919.5	6.2	13.8	7.86	0.00086	
1.879	3.0	379.0	59.93	29.0	948.5	9.7	9.4	8.46	0.00108	
1.919	3.0	382.0	60.40	25.0	973.5	8.3	10.7	8.96	0.00130	
1.957	2.5	384.5	60.80	24.5	998.0	9.8	9.3	9.54	0.00181	
2.000	2.3	386.8	61.16	28.2	1026.2	12.3	7.5	9.74	0.00192	

FIG C.31 : RECOVERY AS A FUNCTION OF PORE VOLUMES INJECTED

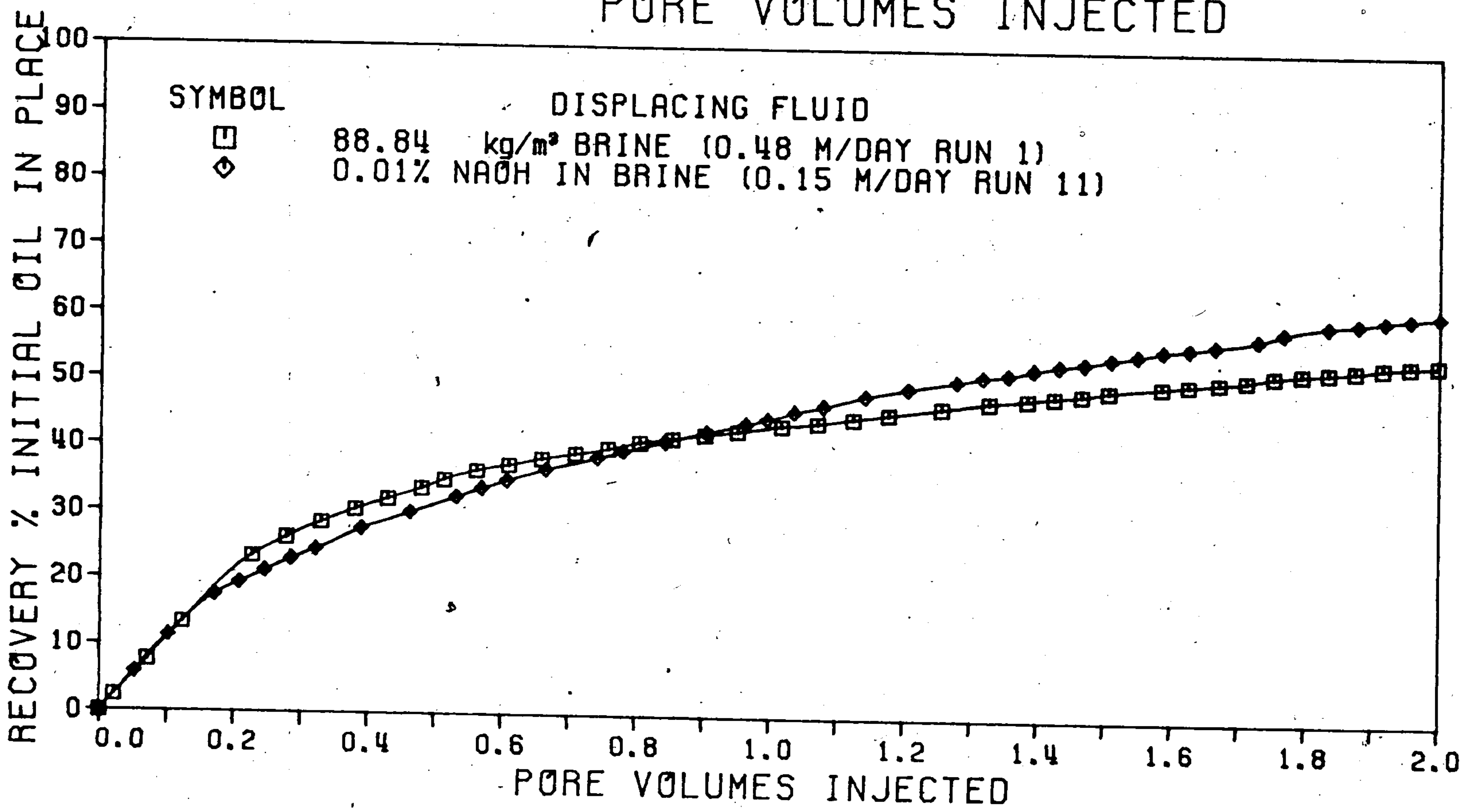

FIG C.32 : OIL CUT HISTORY FOR RUN 11

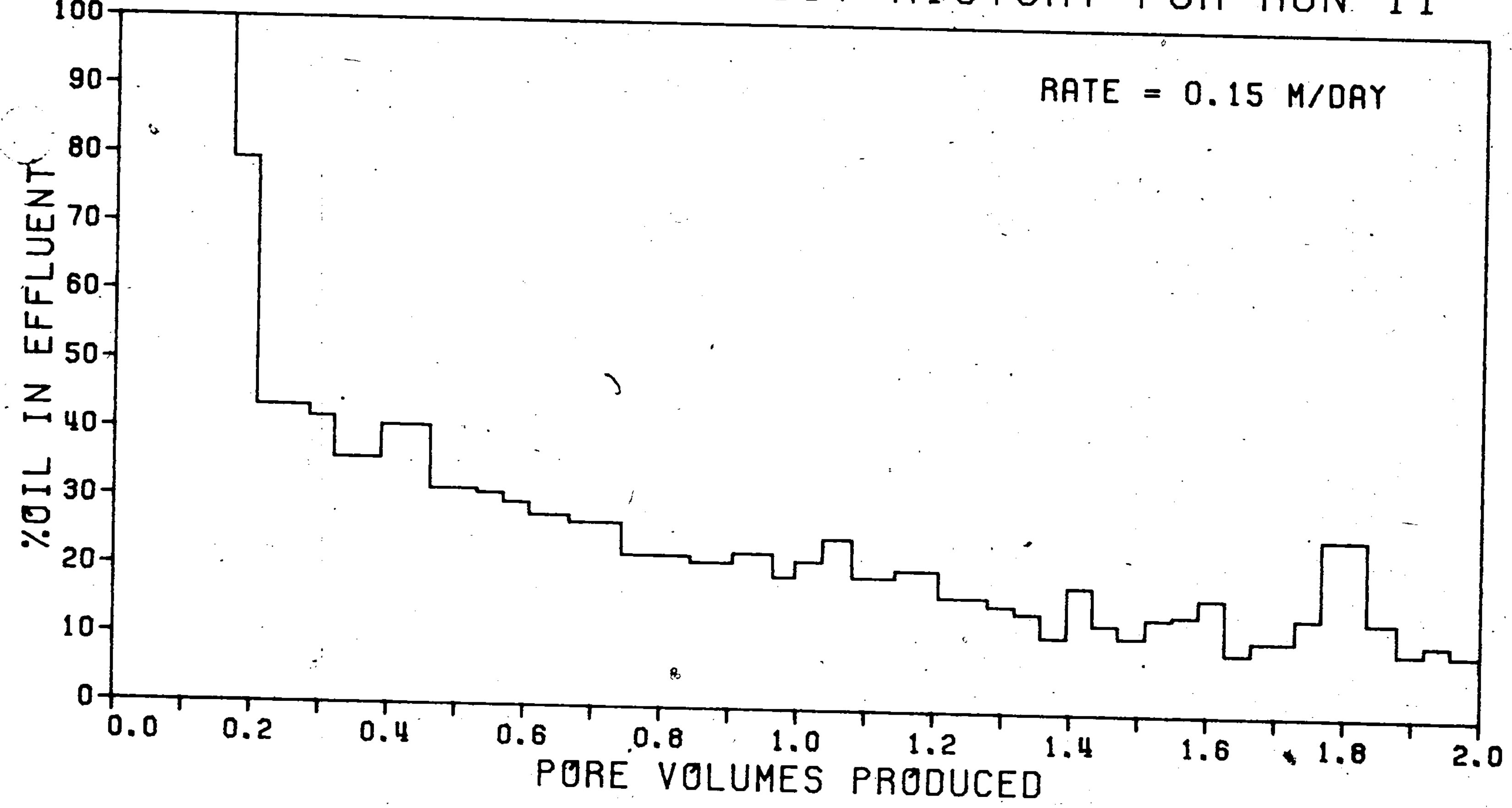

FIG C.33 : RELATIVE PERMEABILITY RATIO RUN 11

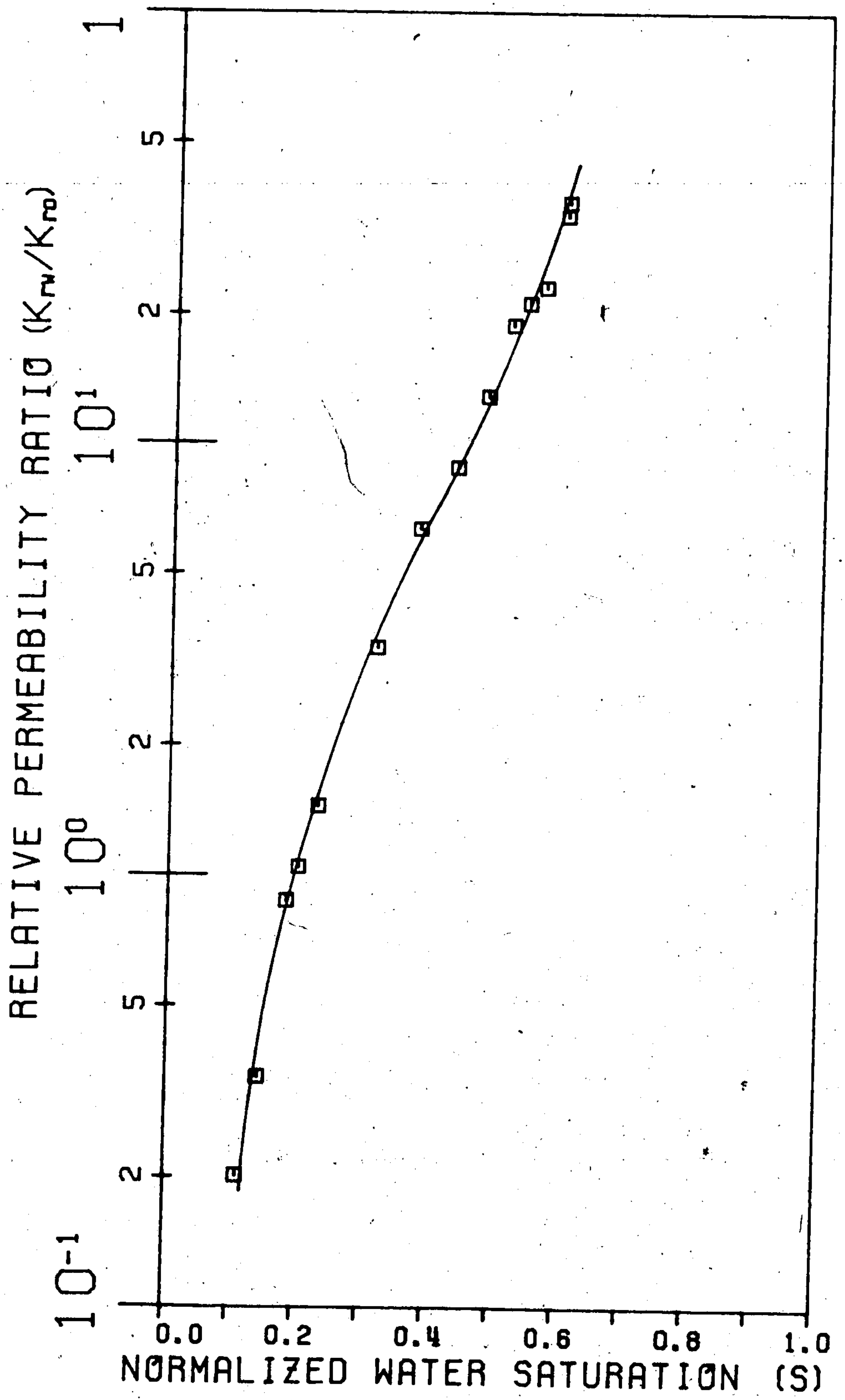

TABLE C-12

CORE 2

RUN 12

CORE PROPERTIES

POROSITY = 35.0 %
PERMEABILITY = 19.0 D
PORE VOLUME = 742.2 ML
INITIAL WATER SAT. = 91.7 ML
INITIAL OIL IN PLACE = 650.5 ML

EXPERIMENTAL VARIABLES

RATE OF INJECTION = 1200.0 ML/HR
CONCENTRATION NAOH = 0.01 WT-%
LINEAR RATE = 14.49 M/DAY

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
0.068	50.5	50.5	7.76	0.0	0.0	0.0	100.0			500.0
0.135	49.5	100.0	15.37	0.0	0.0	0.0	100.0			375.0
0.195	44.0	144.0	22.14	1.0	1.0	0.0	97.8			266.0
0.249	28.5	172.5	26.52	11.5	12.5	0.4	71.2	6.14	0.00045	206.0
0.311	25.0	197.5	30.36	21.0	33.5	0.8	54.3	7.13	0.00073	175.0
0.369	23.0	220.5	33.90	20.0	53.5	0.9	53.5	7.27	0.00076	155.0
0.431	17.5	238.0	36.59	28.5	82.0	1.6	38.0	7.33	0.00077	139.0
0.490	14.5	252.5	38.82	29.5	111.5	2.0	33.0	7.43	0.00079	129.0
0.550	14.0	266.5	40.97	30.0	141.5	2.1	31.8			124.0
0.612	15.5	282.0	43.35	30.5	172.0	2.0	33.7	7.47	0.00079	119.0
0.670	13.5	295.5	45.43	30.0	202.0	2.2	31.0	7.50	0.00080	
0.737	21.5	317.0	48.73	28.0	230.0	1.3	43.4			113.0
0.796	12.0	329.0	50.58	32.0	262.0	2.7	27.3			104.0
0.857	14.5	343.5	52.81	30.5	292.5	2.1	32.2			94.0
0.916	14.0	357.5	54.96	30.0	322.5	2.1	31.8			88.5
0.975	13.5	371.0	57.03	30.0	352.5	2.2	31.0	7.60	0.00082	84.5
1.033	15.5	386.5	59.42	28.0	380.5	1.8	35.6			80.0
1.093	16.0	402.5	61.88	28.0	408.5	1.8	36.4			75.0
1.153	15.5	418.0	64.26	29.5	438.0	1.9	34.4	7.69	0.00085	70.0
1.211	14.0	432.0	66.41	29.0	467.0	2.1	32.6	7.86	0.00076	
1.269	2.0	434.0	66.72	41.0	508.0	20.5	4.7	9.31	0.00152	
1.333	3.0	437.0	67.18	44.0	552.0	14.7	6.4	9.43	0.00162	58.0
1.396	2.5	439.5	67.56	44.5	596.5	17.8	5.3	9.66	0.00181	53.0
1.462	4.5	444.0	68.26	44.5	641.0	9.9	9.2			49.8
1.520	1.0	445.0	68.41	42.0	683.0	42.0	2.3			47.8
1.579	1.0	446.0	68.56	43.0	726.0	43.0	2.3	9.61	0.00177	47.0
1.638	0.5	446.5	68.64	43.0	769.0	86.0	1.1	9.82	0.00199	

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TABLE C-12 CONTINUED

CUM TOTAL INJ (PV)	OIL PROD (ML)	CUM OIL PROD (ML)	CUM OIL %IOIP	WATER PROD (ML)	CUM WATER PROD (ML)	W.O.R	OIL CUT %	PH OF WATER PROD	NAOH CONC WT-%	PRESS DROP (PSI)
1.706	2.0	448.5	68.95	49.0	818.0	24.5	3.9			44.0
1.764	1.0	449.5	69.10	42.0	860.0	42.0	2.3			
1.825	1.5	451.0	69.33	43.5	903.5	29.0	3.3	9.87	0.00205	41.5
1.890	1.5	452.5	69.56	46.5	950.0	31.0	3.1			
1.947	1.0	453.5	69.72	41.5	991.5	41.5	2.4			
2.004	1.5	455.0	69.95	40.5	1032.0	27.0	3.6	9.92	0.00213	38.5

FIG C.34 : RECOVERY AS A FUNCTION OF PORE VOLUMES INJECTED

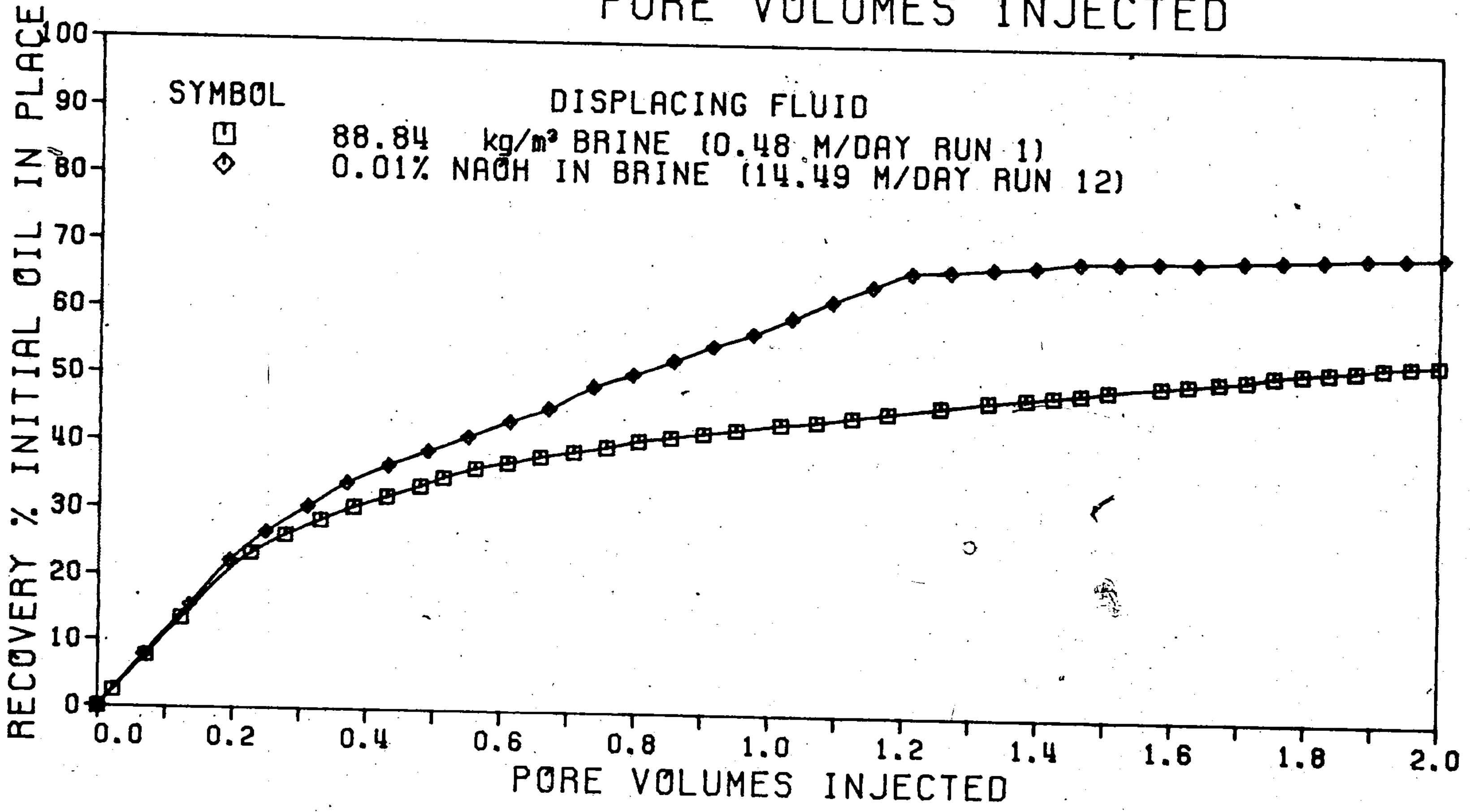


FIG C.35 : PRESSURE AND OIL CUT HISTORIES FOR RUN 12

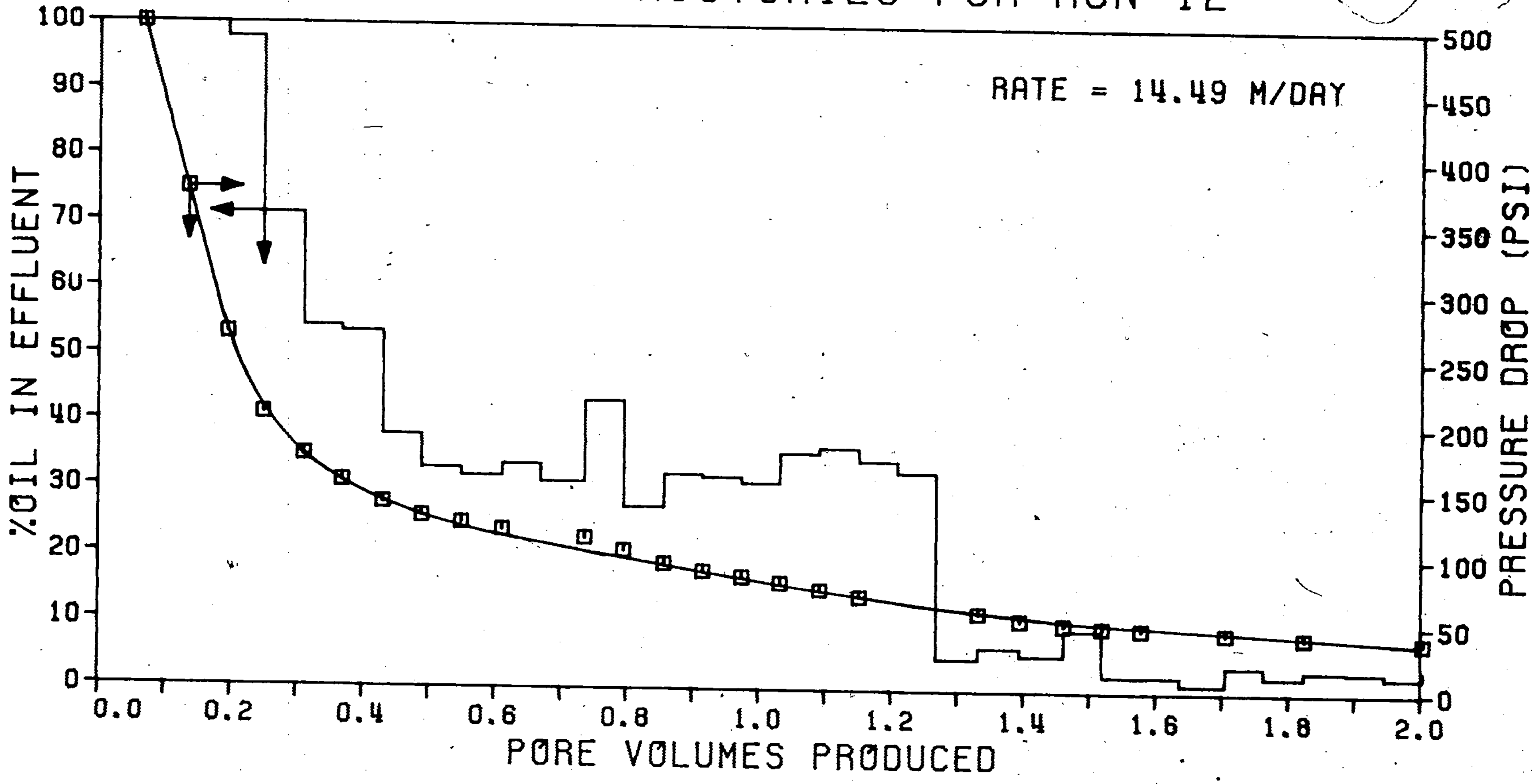
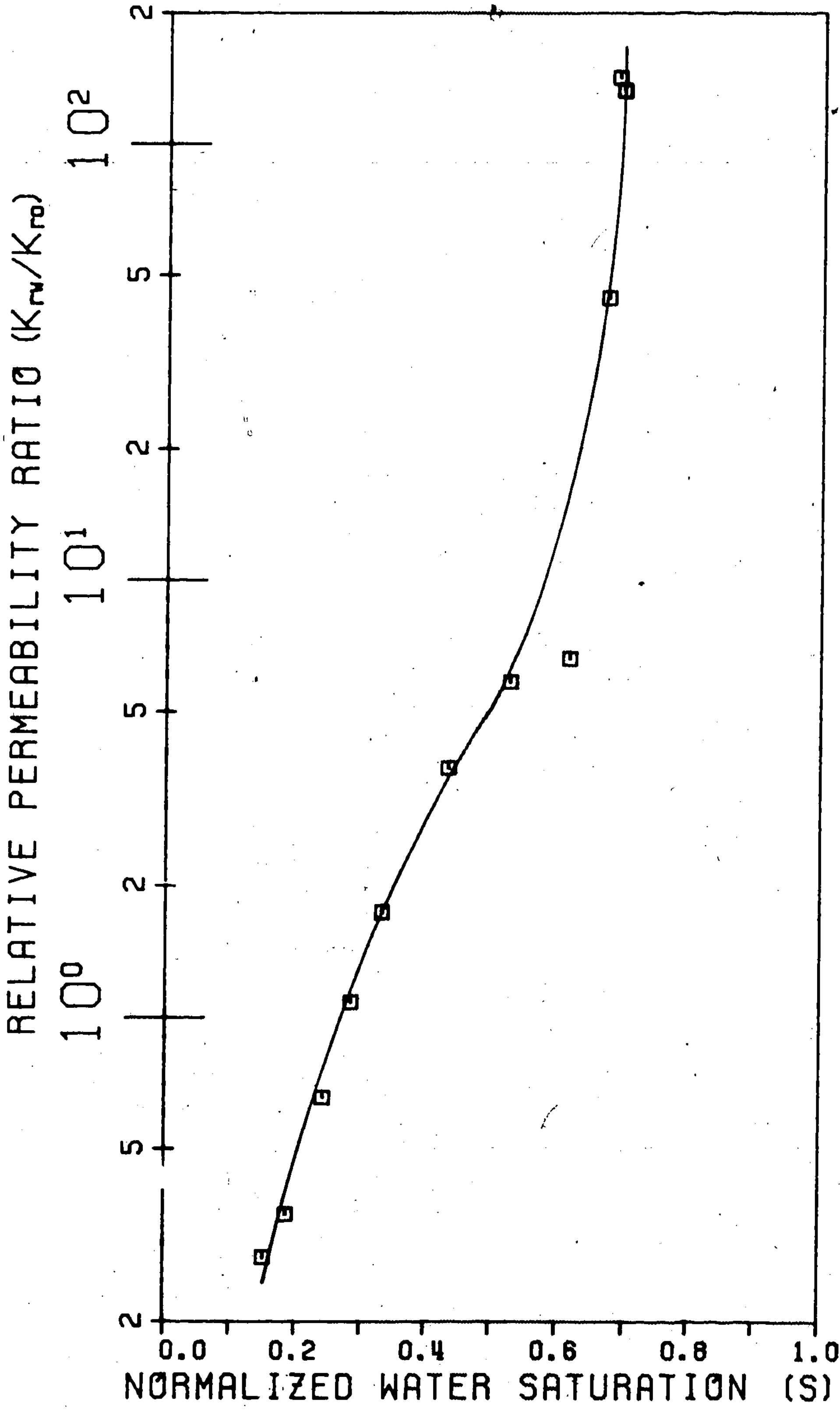


FIG C.36 : RELATIVE PERMEABILITY RATIO RUN 12



APPENDIX D

Data from Adsorption Study. Run 13

Table D- 1

Comparison of Measured and Predicted Normalized Brine Concentration Profiles

Predicted Profile from Equation 1
Experimental Data from Run 13

Dispersion Coefficient: 2.312×10^{-7} m²/sec
Time to Inject 1 PV : 2128.6 sec
Pore Volume : 709.2 ml

Pore Volumes Injected	Measured Concentration	Calculated Concentration
0.890	0.000	0.000
0.949	0.014	0.040
0.969	0.077	0.146
0.992	0.239	0.394
1.010	0.585	0.631
1.038	0.796	0.894
1.054	0.873	0.961
1.072	0.930	0.990
1.093	0.937	0.999
1.114	0.944	1.000
1.141	0.951	1.000
1.160	0.958	1.000
1.178	0.965	1.000
1.196	0.993	1.000
1.239	0.993	1.000
1.250	1.000	1.000

Table D- 2

Comparison of Measured and Predicted Normalized Caustic Concentration Profiles

Predicted Profile from Equation 23
Experimental Data from Run 13

Dispersion Coefficient: 2.312×10^{-7} m²/sec
Rate Constant K_1 : 9.750×10^{-4} sec⁻¹

Pore Volumes Injected	Measured Concentration	Calculated Concentration
0.849	0.000	0.000
0.908	0.001	0.000
0.930	0.001	0.000
0.953	0.003	0.001
0.973	0.005	0.004
0.996	0.007	0.009
1.017	0.027	0.014
1.037	0.106	0.016
1.058	0.205	0.018
1.077	0.295	0.018
1.097	0.379	0.018
1.121	0.464	0.018
1.148	0.566	0.018
1.169	0.663	0.018
1.193	0.783	0.018
1.215	0.819	0.018
1.239	0.843	0.018
1.272	0.892	0.018
1.561	0.952	0.018
1.778	0.976	0.018