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AN EXPERIMENTAL INVESTIGATION OF

THE STEAM DISPLACEMENT PROCESS

IN POROUS MEDIA

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Alfred Eugene Trimble

ABSTRACT

The primary mechanisms of oil displacement by steam, as described in the literature, are viscosity reduction and distillation. However, an analysis of recent results from theoretical and experimental studies, suggests that the basic mechanism of steam displacement in porous media is incompletely understood.

The purpose of the present experimental investigation was to study the steam displacement process in porous media without the benefit of viscosity reduction and oil distillation and to isolate the suspected recovery mechanism. In specially designed experiments, two consolidated sandstones of widely different permeabilities were saturated with oil and flooded with variable quality steam at constant injection temperature and rate. The recovery mechanism of steam was then examined within the context of the effect of pore size, as indicated by absolute permeability, on oil recovery.

Supplementary experiments were required on steam mobility in porous media and on relative permeability. Substantiated data is presented for the first time on the mobility of wet steam in porous media—both with and without

residual oil saturation—and on the effect of temperature on two-phase relative permeability curves in consolidated porous media.

Results showed that steam mobility in porous media decreased with steam quality. This increase in favorable mobility ratio between displacing and displaced fluids was not reflected in an increase in oil recovery but instead oil recovery declined with decreasing steam quality. The oil recovery however could be explained with a new postulated steam recovery mechanism as explained in the text.

The effect of pore size on oil recovery with quality steam did not significantly affect total oil recovery. Surprisingly at low qualities the core with the smaller pores yielded a lower oil recovery even with a larger volumetric amount of available liquid water.

TABLE OF CONTENTS

LIST OF TABLES

Table | Page

LIST OF ILLUSTRATIONS

Figure		Page

Figure		Page

AN EXPERIMENTAL INVESTIGATION OF THE STEAM DISPLACEMENT PROCESS IN POROUS MEDIA

CHAPTER I

INTRODUCTION

The possibility of injecting steam into an oil reservoir to displace oil was first investigated by Stoval in 1934.[48] He demonstrated that the displacement of oil by superheated steam was feasible but the prevailing economic conditions rendered the idea impractical.

Steam injection as a recovery process continued to receive very little attention until the latter 1950's. The results from a pilot test started in 1958 by Shell Oil of steam injection in the Yorba Linda Field, California, established favorable economics. By 1966, the number of steam projects reported in operation in California had increased to 339. Approximately 90% of these projects were "steam-soak" operations.[4]

"Steam soak", "huff and puff" or "cyclic-steam injection" are all names for a process which is basically a formation stimulation process. Steam is injected through an injection well and into a reservoir containing a crude oil of high viscosity for about a week. The well is then shut-in and the heat from the condensing steam reduces the viscosity of the heavy crude. After a sufficient "soak" period, the oil is produced back through the injection well until production declines to an unsatisfactory level. This production may last several months. Steam is again injected into the well and the whole process repeated. These cycles of steam injection are continued until the oil production per unit of injected steam is uneconomical. Much low-gravity oil is still in the reservoir but the limited areal extent of the steam penetration into the formation from the injection well requires a new recovery process if more oil is to be recovered.

An effective way to recover additional amounts of this remaining oil is with a steamflood on a pattern basis. In this process, steam is continuously injected into injection wells and the oil is displaced to separate producing wells. This steam drive process however is not limited to oil recovery after cyclic steam injection. It is rapidly becoming a secondary method that is used after a hot or cold waterflood,[5] after primary recovery,[50] or as the best way to initially produce the oil.[29]

The large reserves available and the tight economics involved have tended to suppress the publication of research and technology on steamflooding. The few papers that have made a contribution to an understanding of the steam displacement process stand out in sharp contrast in the literature.

One of these papers was published in 1961 by Willman and a group of co-workers.[53] They reported the results of a detailed laboratory investigation of oil recovery be steam injection. They believed that the principal mechanisms for the additional oil recovery from a steamflood over that of a waterflood was (1) thermal expansion of oil, (2) oil viscosity reduction and (3) steam distillation of the oil.

The role of viscosity reduction in the recovery process is to develop a more favorable mobility ratio for the displacement of oil by the steamflood. This mobility ratio is a fundamental concept in displacement theory in the oil industry. It is defined as the mobility of the displacing fluid divided by the mobility of the displaced fluid. If steam displacing oil is used as an example then the mobility ratio can be represented as

$$M = \frac{K_{rs}/\mu_s}{K_{ro}/\mu_o} \qquad (1)$$

As the mobility ratio grows larger than 1, the displacing fluid tends to channel and bypass oil resulting in less displacement efficiency. At lower mobility values, the displacement process is more uniform and greater displacement efficiency results.

From the time steam leaves the steam generator at the surface, enters the wellbore and finally condenses in the reservoir, the steam quality is changing. The effect of variable steam quality on oil recovery was investigated by Halbert.[18] He found that the quality of steam injected into a linear core had a definite effect on oil recovery. In a part of his theoretical discussion he reports unconfirmed results of another investigator who found a mobility discontinuity between saturated water and low quality steam. Using this data as control he presented approximate results on steam mobility as a function of oil saturation. This was not an objective of the research but one of necessity in trying to explain his qualitative oil recovery results.

Of particular interest to the present investigation is the result reported in Halbert's work that as steam quality decreases both steam mobility and oil recovery decrease. This means that as the mobility ratio of steam and oil becomes more favorable, the oil recovery <u>drops</u>. This suggests that perhaps the mechanism of the steam displacement process is incompletely understood. Halbert attempted to explain this behavior with a critical time concept similar to that of Mandl and Volek,[24] where the basic mechanism of displacement changed from steam-liquid to liquid-liquid. Difficulties arose in trying to apply his unsteady-state theory to a steady-state flood after steam breakthrough.

Shutler reported the results of a numerical, three-phase simulation of the linear steamflood process in 1969.[36] In demonstrating the validity of his math model, he simulated the steam bank process (steam injection followed by cold water). He noted that where an oil saturated core had been exposed to steam that the residual oil saturation was less than elsewhere. His math model could not handle oil distillation so this was eliminated as a mechanism. When he injected the water following the steam at steam temperature so that the entire core was flooded at steam temperature, he still found that the region of the core which had been exposed to steam had a lower residual oil saturation. Therefore temperature was also eliminated as the cause of additional recovery.

With temperature and steam distillation eliminated—which were the principal mechanisms of the Willman et al[53] experiments—then the question arose as to what caused this oil additional recovery. Shutler suggested that a "condensing drive" mechanism was responsible which effectively flooded many pore volumes of gas through a portion of the core, but upon condensation a much smaller volume of fluids needed to be handled at the production end. This means that high displacement efficiency—with respect to fluid production—is possible for a steamflood without the benefit of distillation.

Statement of the Problem

The steamflood process is complex and some parts of it are not completely understood. As previously discussed, it is known that the steamflood improves recovery by viscosity reduction and oil distillation. It is also known that oil recovery varies with the quality of the displacing steam.

However the problem is posed as to what happens to oil recovery with injection of a spectrum of isothermal quality steam without the benefit of oil distillation or viscosity reduction. Further, what is the relation between oil recovery under these conditions and steam mobility both with and without residual oil saturation.

This problem is examined in the present investigation within the framework of another related problem, which is to determine the effect of pore size (as suggested by absolute permeability) on oil recovery with variable quality steam. To amplify the role of absolute permeability also requires that the viscosity reduction and steam distillation mechanisms be minimized or removed from the steamflood.

A series of experiments was designed to clarify the role of the mechanism involved when isothermal, wet steam displaces oil from different pore sizes without the benefit of viscosity reduction and distillation.

Thermodynamics of Steam

Steam is a one-component system which may be in a superheated or saturated state. Superheated steam, saturated vapor or saturated liquid are called homogeneous systems because they have only one phase. If the steam is a mixture of two phases, then the system is called heterogeneous.

Saturated steam may vary from 100% vapor to 100% liquid at a constant pressure and corresponding temperature. It is redundant to specify both temperature and pressure for saturated steam because only one degree of freedom exists. To specify a given pressure implies a corresponding temperature. Between 100% vapor and 100% liquid, the state of the saturated steam is characterized by steam quality.

Steam quality may be defined as the ratio of the mass of the vapor to the total mass when the system exists as part liquid and part vapor in a saturated state. In terms of the thermodynamic properties of the system, quality may also be defined as the degree to which total heat of vaporization has occurred. Expressed symbolically, this relation is

$$X = \frac{H_t - H_{sw}}{H_{vap}} \qquad (2)$$

where

X = steam quality

H_t = total enthalpy of the system

H_{sw} = enthalpy of saturated water

H_{vap} = latent heat of vaporization

Equation (2) was used to calculate injection quality in the present study.

Excluding total vapor (100% quality) and total liquid (0% quality), the term quality steam, "moist" steam, or "wet" steam designates a two-phase mixture of liquid water and water vapor. Physically a two-phase mixture may be considered from two different aspects. One viewpoint might be that of liquid water droplets dispersed throughout the vapor phase. However when the liquid phase appears as droplets, the effects of surface tension are present and the number of independent variables in the system increases. Vapor pressure of the droplets is not a single valued function of the temperature.[51] A second physical viewpoint is to consider the individual droplets as all condensed within the system boundaries. The vapor phase would then be above the water phase. Wark[51] points out that either of the two viewpoints is physically correct since by definition of a phase, the volumes occupied by two different phases of a system do not overlap.

The range of operating pressures is important to the location of the heat content in wet steam. As pressure increases the total heat in steam varies only slightly, however the latent heat of vaporization decreases while that of saturated liquid (sensible heat) increases. This relationship is shown on Figure 1. It is apparent that the degree of vaporization, as indicated by quality, has a more significant effect on the heat content of steam at lower pressures. For instance, at 100 psia the heat content of 100% quality steam due to latent heat is 75.1% while at 800 psi it has decreased to 57.5%.

As the pressure continues to increase the latent heat eventually goes to zero at the critical pressure. This increase in pressure causes a corresponding increase in temperature of the steam and results in an increase in heat loss to the underburden and overburden. The velocity of a steam front is dependent on injection rate and heat loss. Therefore as the pressure increases the difference between the velocity of a point in the condensing steam front and the velocity of a point in the hot liquid zone of a steamflood increases.

Two other important thermodynamic relations of steam are enthalpy and viscosity. Discussion on these is deferred until their use in the remaining text.

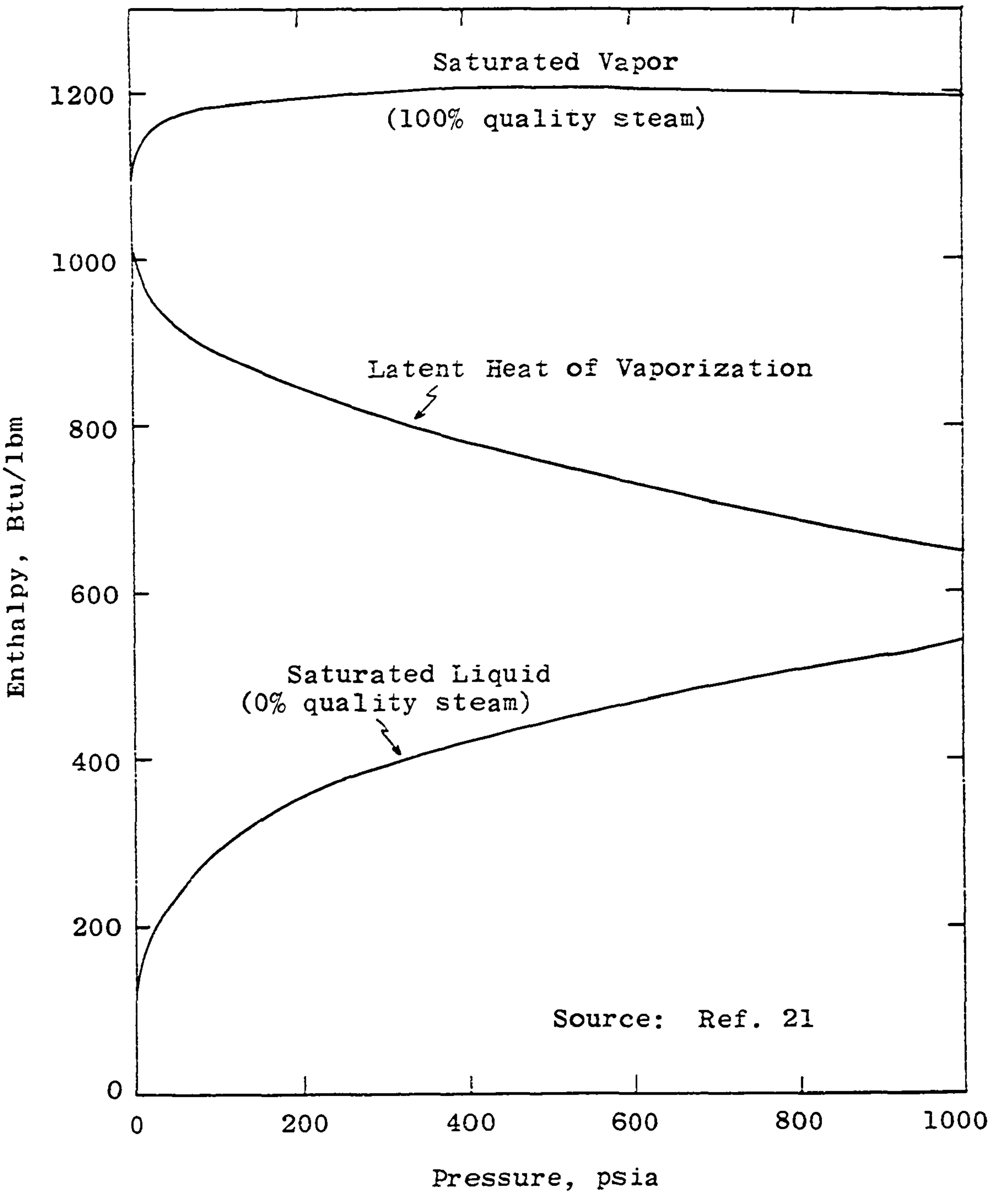

FIGURE 1 EFFECT OF PRESSURE ON THE HEAT CONTENT OF SATURATED STEAM

CHAPTER II

LITERATURE REVIEW

Extensive literature is available on thermal recovery methods. Much of this literature is concerned with determining the temperature distribution and thermal efficiency for the particular thermal process. Reviews of the important contributions in this area, such as Lauwerier[22] in hot waterflooding and Marx and Langenheim[25] in steamflooding, are available in the literature[18,47,16] and will not be explicitly discussed here.

The number of experimental studies reported in the literature on the steam displacement process is quite limited. Both model studies and experimental studies are necessary to advance the knowledge of the steam displacement process and to understand the relation of the different variables. However, in this chapter only the more important experimental studies that relate to the present investigation are summarized. The results from six steam-displacement studies are discussed in chronological sequence. Then the results from papers investigating the effect of temperature on relative permeability and capillary pressure are summarized.

Research of Willman, Valleroy, Runberg, Cornelius and Powers (1961)

An experimental investigation by Willman and coworkers made a significant contribution to an understanding of the mechanisms responsible for the additional oil recovery by steamflood.[53] They identified the principal mechanisms as (1) thermal expansion of the oil, (2) viscosity reduction and (3) steam distillation. Two additional minor mechanisms—gas drive and solvent effects—were discussed and experimental evidence presented to suggest that they were contributing factors to the recovery process.

The 12 cores which were used varied from 17.3 cm to 104.0 cm in length and from 5.4 cm to 17.5 cm in diameter. Water permeability varied from 116 to 3030 md. Steam and hot waterfloods were performed at 330°F. Neither injection rates nor heat-loss data were given but interpolation from one of their figures shows an approximate time for steam breakthrough for a 91.4-cm core of 340 minutes. This is a front advance of 0.27 cm/min.

Results indicated hot waterfloods recovered more oil than cold waterfloods and steamfloods more than either. The increased recovery for the hot waterflood was believed to be caused by viscosity reduction and oil expansion.

Viscosity reduction with the application of heat improves displacement efficiency which increases oil recovery for a given practical producing water-oil ratio.

Willman and co-workers also believe that oil viscosity reduction by condensing vapor in front of the steam front ("solvent effect") contributes to the total oil recovery by further increasing displacement efficiency. Recent investigations[30,38] suggest that part of the increased displacement efficiency with heat application may be due to an increase in rock wettability with temperature.

Willman and co-workers suggest that a "gas-drive" mechanism operative in the steam zone increases recovery (approximately 3%). Experiments designed to simulate this process involved injecting alternate slugs of 330^{o}F nitrogen and 330^{o}F water. The purpose of this procedure "was to simulate steam as a gas and practice a three-phase flow in the core". The investigators probably produced three-phase flow but they may not have simulated the process desired. To model a one-component, two-phase system in a saturated state with a two-component, two-phase system in a non-saturated state can lead to possible error. Failure to properly evaluate this mechanism combined with an incomplete description of their "solvent effect" experimental determination is believed to have caused some discrepancies and unexplainable experimental results (e.g. larger solvent-effect recovery from lower distillable oil).

Research of Abbasov, Kasimov and Tairov (1964)

Abbasov and co-workers reported the results of an investigation of oil recovery where they injected superheated steam into a sand pack containing oil and a residual water saturation.[1] The sand pack was 3.275 ft in length and 1.5 inches in diameter with a permeability that varied from 12.24 to 13.73 darcys and porosity from 37.55 to 38.04%. The crude oil used in the experiments had a density of 0.926 g/cm^3 and a viscosity of 230 cp at atmospheric conditions. The purpose of the study was to investigate the effect of temperature and injection rate on oil recovery with superheated steam.

The results show that for a constant pressure drop across the core of 1.5 atmospheres, the ultimate oil recovery increased from 88.37% to 97.59% for a temperature change from 125^{o}C to 300^{o}C. They list the suggested mechanisms that caused the increased recovery as: (1) reduction of polarity of the crude oil; (2) "reduction of the anomalous layer of crude oil on the mineral grain surface and breaking up of the anomalous layer of crude oil heated by the water"; (3) thermal expansion of the oil; (4) distillation of crude oil by steam and; (5) the "washing away of the oil by the condensing light components emanating from the steam zone".

Abbasov and his co-workers also found that a maximum recovery existed for a continual increase in the injection rate at a temperature of 250°C. The explanation offered was the interplay of two factors: (1) increasing the injection rate increased the temperature of the formation by reducing heat losses which lead to increased recovery and, (2) increased injection rates lead to an early breakthrough and by-passing of oil. Initially the thermal factor was dominant but after the maximum recovery was reached, the by-passing of oil with early breakthrough became dominant.

Research of Halbert (1967)

Halbert established that oil recovery from consolidated sandstone was responsive to the injected steam quality.[18] He injected 382°F isothermal, variable-quality steam into two Boise sandstone cores of 12 inches and 22 inches in length and 2 1/8 inches in diameter. Three crude oils were used which had gravities of 27.4°, 24.3°, and 15.4° API and corresponding viscosities at 80°F of 21 cp, 124 cp, and 1050 cp.

The experimental results showed oil recovery to definitely increase with injected steam quality until about 75% quality. The use of higher quality steam did not further increase oil recovery. A constant injection rate of 15 g/min was used on the experiments.

An additional result was that the oil recovery increased with oil gravity except between the approximate injection steam qualities of 15 and 60% where the results were mixed.

Halbert presented the hypothesis that displacement efficiency may be governed by the steam-to-oil mobility ratio for a critical time duration, the length of which is a function of steam quality and the system's thermal properties. After this critical time, displacement was governed by liquid-liquid displacement principles. Mandl and Volek,[24] using a more rigorous mathematical approach, also developed a critical time concept where the basic displacement mechanism changes in the steamflood. Application of this theory to unsteady-state experiments may be more fruitful than to steady-state experiments. This observation is based on results of the Willman et al[53] experiments, which have been substantiated,[27] where ultimate oil recovery by steamflood was independent of prior waterflood history.

Research of Araujo (1968)

Araujo encountered several problems in his investigation of the effect of steam quality on oil recovery.[2] He reported unsuccessful efforts to use a calorimeter to measure steam quality because the possible error was as much as 20%. He used a throttling method to measure the steam quality but the method was limited to high steam pressures and high qualities.

Araujo's search for a means to determine the injected steam quality may have been partly academic. His equipment was designed to have a static, high-temperature, heat transfer oil in the annulus surrounding the core. Whenever he matched his core inlet temperature with his annulus inlet temperature he had superheated steam at the core outlet. His limited experimental results show superheated steam at the outlet in all cases. His lowest inlet quality was 95%.

Apparently the experiments were used as a basis for a computer model study as no experimental recovery results are discussed. The model he used was modified from one he reports was obtained from his faculty advisor—Farouq Ali. The model was unexplained but was reported to use the approaches of both Marx and Langenheim[25] and Willman and coworkers[53] for the calculation of the steam zone and hot waterflood.

Conclusions from the computer predictions were that "oil recovery should be expected to increase with an increase in steam quality. The actual magnitude of the increase was found to depend upon steam pressure, injection rate, and characteristics of the oil involved. The effect of steam quality on pressure drop did not show a consistent trend."

Research of El-Saleh and Farouq Ali (1968)

El-Saleh and Farouq Ali presented the results of an experimental steamflood and math-model study.[13] In the experiments a 4-inch by 1.5-inch rectangular tube 4 feet in length was packed with glass beads. The permeability and porosity of the pack were 4.37 darcys and 39.8% respectively. The top and bottom surfaces of the core were in contact with thick layers of sand (2.5 ft) which simulated underburden and overburden. The fluids used were Drakeol 15, Drakeol 33, and mixtures of the Drakeols and isooctane.

A constant pressure drop across the core was maintained on the 16 runs reported which required that injection rate vary with time. As a consequence the results were difficult to interpolate and as the writers note, the variable injection rate added to several problems they encountered with their math model.

They concluded that over the range of 284^{o} to 350^{o}F, steam temperature had only a slight mixed effect on oil recovery. This observation was made by the writers on 4 runs with Drakeol 33 whose boiling range was 680-920^{o}F with a viscosity of 50.5 cp at 80^{o}F.

Research of Ozen and Farouq Ali (1969)

Ozen[26] and Ozen and Farouq Ali[27] reported the results of steamflood tests on Berea sandstone and glass beads. They conducted 21 of 25 runs in cores that had been previously waterflooded. In the remaining runs, the cores initially contained irreducible water. No two of the runs were conducted under the same conditions. A Bradford crude was used which had a gravity of 45^{o}API and a viscosity that varied from slightly over 4 cp at 80^{o}F to about 0.8 cp at 300^{o}F.

An interesting conclusion presented in Ozen's thesis was that "recovery of the Bradford crude by continuous steam injection at room temperature is much higher than would be distilled at the steam temperature. This is attributed to the beneficial effects of steam distillation present in such a process." This conclusion is not clear in view of negligible effects on viscosity of this oil by heat and by the solvent effect of the distillate. The magnitude of this increase in recovery over that by distillation was not given but it appears to be caused by the displacement mechanism that the present investigation has isolated.

Another conclusion of the writers is that residual oil saturation following a steamflood is independent of the initial oil and water saturation. This is another verification of the Willman et al[53] experiments.

By varying the heat losses of the core for different steamflood runs, the writers concluded that lower heat losses resulted in higher recoveries. In effect this is in agreement with Halbert's[18] work as steam quality is determined by heat loss.

Research of Poston, Ysrael, Hossain, Montgomery, and Ramey (1967)

The results of a continuous study at Texas A & M, which was started by Ysrael and concluded by Poston, are presented in this paper.[30]

The primary objective was the determination of imbibition relative permeability to oil and water for isothermal displacement from unconsolidated sand at various temperature levels. A natural oil sand and a clean quartz sand with approximate porosity and permeability of 37% and 1.5 darcys respectively were used as the porous media. Three refined oils (26.0°, 22.4°, 23.6° API) were used with respective viscosities at 75°F of 80 cp, 99 cp and 600 cp. Temperature level varied from 75°F to 275°F. Relative permeability ratios were determined using the method of Welge[52] while individual relative permeabilities were calculated using the method of Johnson, Bossler, and Naumann.[20]

Several significant results were obtained from this study:

(1) The irreducible water saturation increased with increasing temperature. Oil viscosity appeared to have had no real effect on the results.

(2) The practical residual oil saturation (WOR = 100) decreased with increasing temperature.

(3) The water-oil relative permeability ratio appeared temperature sensitive but there was no definite trend.

(4) The relative permeabilities to both oil and water generally increased with increasing temperature. There was a reversal in water relative permeabilities at low water saturations.

Another conclusion reached by Poston and co-workers was that water-oil imbibition displacements in water-wet unconsolidated sands become more efficient with increasing water wetness as the temperature level increases.

Research of Sinnokrot, Ramey and Marsden (1969)

As a result of speculation in the Poston et al[30] paper that capillary pressure-saturation curves should be temperature dependent, this study was made.[38] Drainage and imbibition capillary curves were measured for three consolidated sandstones and one limestone at either

3 or 4 temperature levels from 70° to 325°F. The fluids used were filtered white oil and distilled water.

Results from this paper can be summarized as follows:

(1) Capillary pressure curves for the sandstone proved highly temperature sensitive and were displaced toward higher wetting phase saturations with an increase in temperature level. This is believed to indicate an increase in water wetness with temperature increase.

(2) In contrast, the limestone sample indicated negligible temperature sensitivety.

(3) As in the Poston et al work, the practical irreducible water saturation increased markedly with temperature level increase for the sandstone samples.

(4) However, in contrast to the Poston et al work, calculation of relative permeability curves from the capillary pressure data showed the expected increase in K_{ro} but a <u>decrease</u> in K_{rw} with temperature increase.

(5) Investigation of current theory is inadequate to explain the experimental results obtained on the sandstones.

CHAPTER III

THEORETICAL CONSIDERATIONS

Difficulties have always been encountered when describing flow behavior in porous media on a microscopic (pore size) basis because of the complex flow paths. A recent paper on heat flow which made an observation on fluid flow that "In reality, 'steam quality' probably has no meaning in porous media since liquid and vapor would exist separately"[33] has merit but may be a little harsh when examined more closely. The purpose of this chapter is to briefly discuss the theoretical and thermodynamic considerations involved in an analysis of steam flow and steam displacement in porous media.

Steam Flow in Porous Media

In considering steam flow through porous media, the initial problem that needs to be resolved is the type of steam flow involved. Does wet steam flow through porous media as a homogeneous fluid, as a heterogeneous mixture or as a combination of both? Before discussing the theoretical arguments for each flow type, it might be instructive to determine exactly how much liquid water is present in wet steam at a given temperature and pressure.

The contribution of liquid water in wet steam can be expressed as

$$S_w = \frac{v_f(1-x)}{v_f(1-x) + x\ v_g}(100) \qquad (3)$$

where:

S_w = liquid-water saturation expressed as percent total water

v_f = specific volume of the liquid

v_g = specific volume of the vapor

x = steam quality

As density is the reciprocal of specific volume, the relation can also be shown as:

$$S_w = \frac{\rho_g(1-x)}{\rho_f x + \rho_g(1-x)}(100) \qquad (4)$$

where ρ is the density. If either of these two equations are used to calculate a series of saturations for variable-quality steam at constant pressure, then the results can be shown as Figure 2. This figure shows that if a 20% quality steam is injected into a core at a mass rate of 20 g/min and an average pressure of 200 psia, the water contribution to the total water saturation of the core is only 0.61 g/min. At 80% quality steam, the water contribution would only be 0.04 g/min. Thus the relative water contribution from

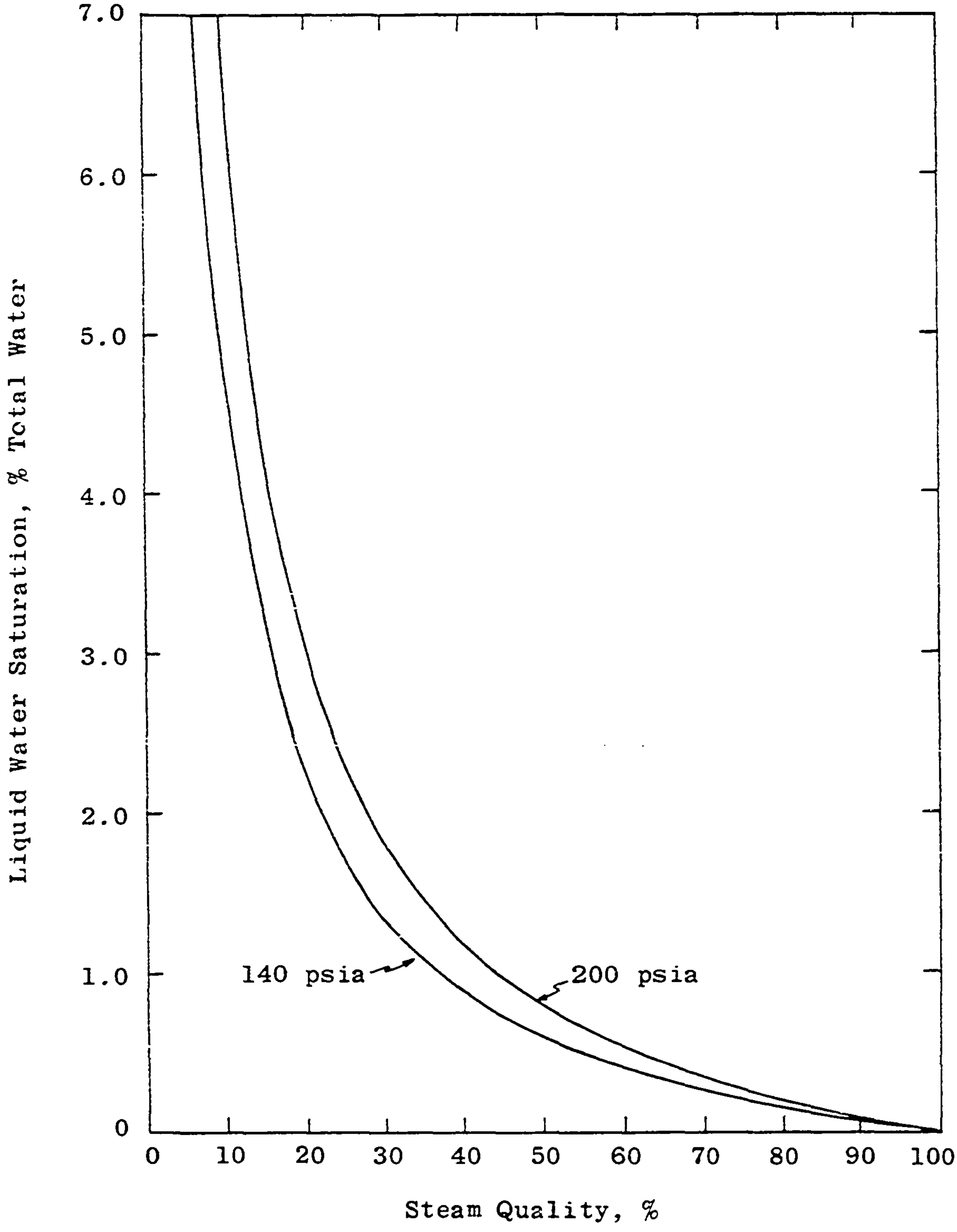

FIGURE 2 PERCENT LIQUID WATER IN WET STEAM

non-condensing, wet-steam flow on a mass-rate basis is quite small.

Using an argument similar to that above, Araujo[2] assumed that wet steam flows through a given porous medium as a homogeneous mixture of dry steam and finely divided water droplets. He recognized this approach neglected the separation of water from wet steam resulting from abrupt direction changes in the pores. Using this assumption he derived an expression for the apparent viscosity of wet steam as a function of temperature, pressure, and steam quality. This concept of homogeneous steam flow was used in Araujo's computer study and also by El-Saleh and Farouq Ali[13] in their computer model.

Theoretically the concept of homogeneous steam flow through porous media is feasible if the assumption that no capture of the dispersed liquid occurs through the porous media. One of the simpler porous media models reviewed by Scheidegger[34] (such as the straight capillary model) might be useful in such an analysis. However as the model becomes more sophisticated, such as the one by Fatt and Dystra,[15] then "flake off" of the water droplets must be considered and a different analysis would be necessary.

The argument based on low liquid-water content is a strong one for homogeneous steam flow. Although wet steam is a two-phase mixture, the small percent of dispersed liquid water does not permit two-phase flow due to flow of the quality steam alone. Even if interphase mass transfer is allowed and the quality decreases, Figure 2 shows that the water contribution is small until very low qualities are reached. An implicit assumption in homogeneous steam flow is that the dispersed drop size is smaller than the pore channel size. As quality decreases these droplets probably increase in size rather than number which will increase liquid water capture.

With phase separation, the mechanics of steam flow become complex. An inherent problem is the fact that the two phases are miscible. With only a slight change in enthalpy the phase distribution of the mixture can change. This relationship can be seen from the pressure-enthalpy chart in Figure 3.

If a given quality steam is injected into a core and the core's external heat loss is controlled in the manner shown by Figure 3, then the exit steam quality must equal the inlet steam quality under steady-state conditions. Further, if the inlet steam quality enters the core face as liquid water dispersed in the vapor and exits as vapor with condensed liquid water, then as long as the system of investigation is externally controlled in the manner described above, exit steam quality will equal inlet steam quality. As pointed out in the introductory chapter, the volumes occupied by two different phases within a system do not overlap. Under these conditions, thermodynamics

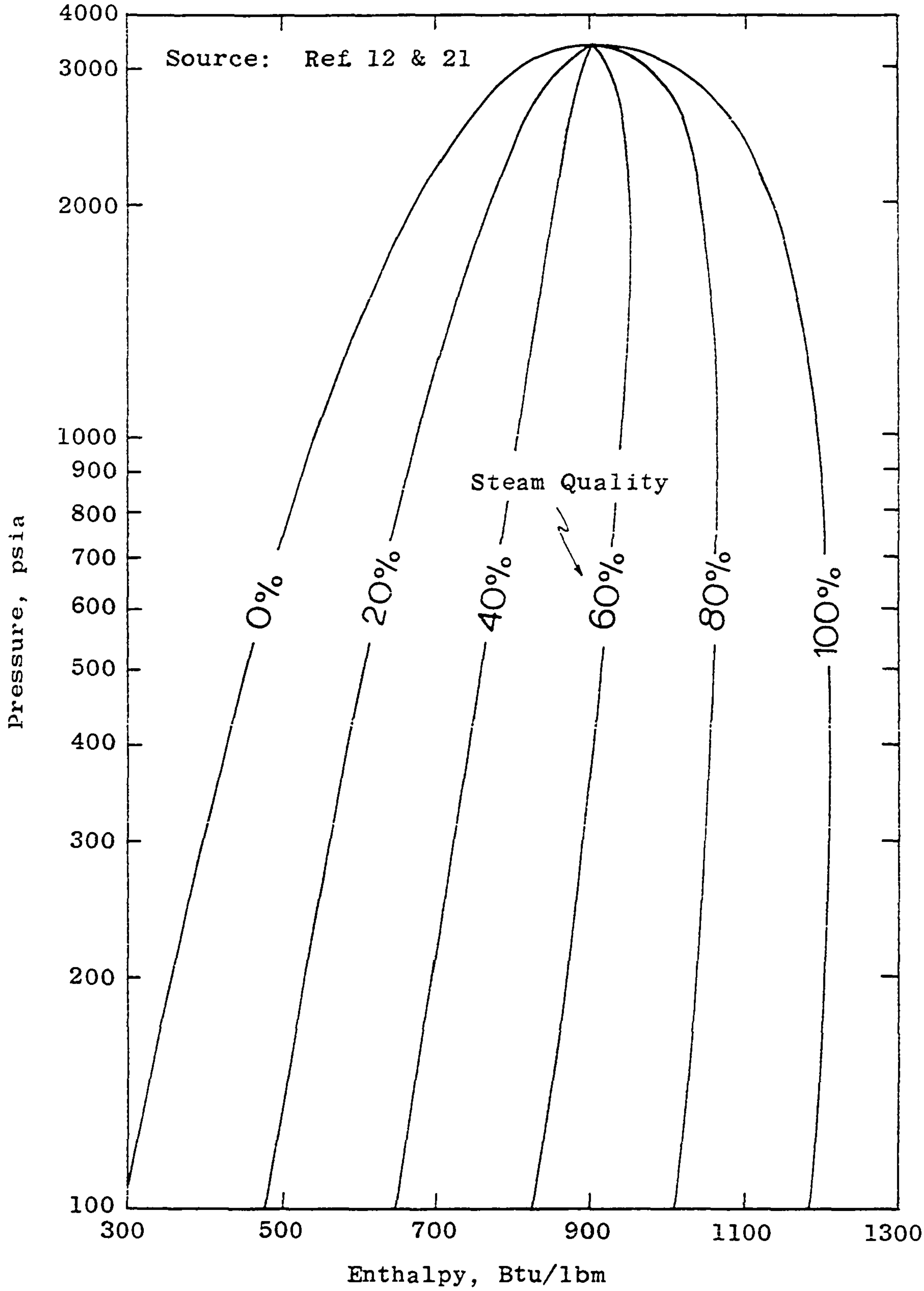

FIGURE 3 PRESSURE VS ENTHALPY FOR WATER

applied to a macroscopic system shows that the term steam quality when applied to porous media has a firm foundation.

Now suppose that the control volume of analysis is decreased in size to cover several pores instead of the entire core or chunk of rock. Does steam quality still have meaning? It does only if we don't violate the thermodynamics involved. However we are now in the awkward position of trying to evaluate the injected steam quality to the shrunken control volume and manipulate the heat losses to the surrounding pores.

We have no basis for assuming the injected steam quality remained constant as our control volume shrunk, nor can we control the heat losses. In brief, we have lost control over steam quality on a microscopic basis. Now we must look to those internal rock forces that control fluid flow and distribution.

As discussed earlier, a weakness of the homogeneous concept of wet steam flow was that as the porous media became more complex the "capture rate" of the suspended liquid water increased. These suspended droplets are coalesced into the bulk of previously captured liquid. The coalesced liquid then moves through the porous media by gravity, hydrodynamic, and capillary forces.

According to the channel-flow concept,[6] multiphase flow does not occur in a microscopic channel. The fluids tend to flow separately in different pore sizes with boundaries which consist of solid-fluid and fluid-fluid interfaces. For three-phase flow, the vapor would ideally flow through a channel system connecting the larger pores, the oil through an intermediate-size pore system, and the water through the smallest pore sizes. The basis for this theory is visual observation,[6] and fundamental capillary considerations.[7,34]

For constant-quality steam displacement of non-distillable oil the vapor with or without dispersed water droplets would displace the oil from the larger pores. With sufficient coalesced water buildup in the water-wet porous media, capillary forces would place the water in smaller pores and displace additional oil. When the imposed pressure gradient became larger than the capillary forces, then more oil would be forced from the smaller into the larger pores and be displaced by the steam vapor.

On a volumetric water basis, it would appear that the lower quality steam would more efficiently flush the smaller pores. This concept has previously been suggested[18,49] and it was decided to experimentally investigate this hypotheses. To study the effect of pore size, as suggested by absolute permeability, on oil recovery with variable quality steam is a major objective of this research. To amplify the role of absolute permeability in the steamflood process, it was necessary to eliminate or minimize viscosity reduction and distillation. To vary pore size required two different cores with a wide range of absolute permeabilities. To compare recovery between the cores required relative permeability studies and so the experiments grew. These are discussed in more detail elsewhere, but the point here is that this approach was also leading to an investigation of a fundamental problem—the mechanism of the basic steam displacement process which will be discussed shortly.

If the macroscopic restriction of constant steam-quality flow through the system of investigation (such as a core) is retained, but the microscopic restriction is removed (we have no control anyway) then the following analysis seems plausible. Suppose a control volume is set over several pores and the steam quality is analyzed as the steam enters and then leaves the control volume. As the steam enters, some of its liquid water is captured and left outside of the control volume. The steam is now out of equilibrium and upon entering the control volume will either pick up or condense liquid, dependent upon the amount of finite pressure drop associated with the flow and the temperature surrounding the control volume. Then the steam will either leave the control volume at a higher, lower, or the same quality as when it entered. This is in accordance with the thermodynamic considerations in Figure 3. If several control volumes are adjoined through the core cross-section, then the average quality from the control volumes must equal the average dictated by our macroscopic conditions on the core. To understand and analyze the "micro" control volumes, whose number would be a function of the heterogenity of the cross-section, would require better microscopic description of the porous media than we now possess.

By combining Darcy's law with the equations of continuity and capillarity a fair description of macroscopic flow is available. However, restrictions in the current theory are becoming more apparent. In particular, the assumptions required to decouple the two flow-equations to extend unsteady-state calculations for relative permeability from two-phase to three-phase flow are untested. Slattery[39] does not believe that the use of Darcy's law and the capillary-pressure equation provide a firm foundation upon which to study multiphase flow of viscoelastic fluids. He is proposing new theory based on local volume averaging of the equations of motion over each phase in a porous media.[39,40] Scheidegger[34] discusses a first attempt at statistical description of a porous media. One of the most recent statistical models is that by Haring and Greenkorn.[19]

Steam Displacement in Porous Media

A theoretical analysis of the mechanisms involved in the displacement of immiscible fluids was originally established by Buckley and Leverett.[5] The large number of experimental investigations made to substantiate the theory and the applications of the theory are discussed in several standard texts,[7,28,34,41] and will not be reviewed here.

An important part of this frontal displacement theory is that the flooding behavior is largely dependent upon the mobility of the displacing phase (K_{rs}/μ_s) relative to that of the displaced phase (K_{ro}/μ_o). Heat affects both of these parameters and must be considered in a steamflood. That heat does significantly affect relative permeability was pointed out by the Poston et al[30] paper previously discussed. Other investigators have found heat affects relative permeability ratios to differing degrees.[9,11,17] All of these studies have been with two-phase relative permeability and none have measured the effect of temperature on three-phase relative permeability.

Only a limited number of three-phase relative permeability studies even at room temperature have been made since the initial pioneer research by Leverett and Lewis[23] in 1941. Not all of these studies (references 8, 10, 31, 32, 42) are in agreement as to the dependency of behavior for each of the phases. A recent paper by Schneider and Owens[35] concluded that some types of three-phase flow behavior can be predicted from two-phase flow data.

Once past the relative permeability problem with its related wettability effects,[17,30] then another immediate problem is encountered with what to use as steam viscosity for wet steam. Various investigators have handled this problem in different manners. Araujo[2] assumed wet steam flowed in a homogeneous manner through porous media and developed a relation from a non-theoretical base. Farouq Ali[14] assumed linear behavior while Halbert felt the viscosity term was a function of density.[18] A discussion of the viscosity problem is given in references 2 and 49. If a usable apparent viscosity term is eventually developed it will probably be a complex relation between the viscosity of the liquid water and the viscosity of the vapor.

With a knowledge that these problems existed, it was decided to obtain steam mobility (K_s/μ_s) directly from the experiments for each core. By calculating this value from Darcy's equation

$$\frac{K_s}{\mu_s} = \frac{M_t v_s L}{A \, \Delta P} \tag{5}$$

over a spectrum of qualities, then an idea of displacement efficiency could be obtained and related to recovery. No substantiated data of this type appears in the literature.

Because of the complexities, no attempt was made at determining three-phase relative permeability data. However, for the basic comparative study between the two cores selected, the effect of temperature on the porous media was required and was obtained by hot waterfloods.

The final theoretical question posed was the steam displacement mechanism if viscosity reduction and steam distillation were removed or minimized. When Darcy's equation which governs flow through porous media is examined, the only variable left is specific volume of the displacing phase—steam. At 200 psi, the specific volume decreases by a factor of 124 in going from saturated vapor to saturated liquid. Therefore this type of condensing volume change has to be a major factor in the excellent sweep efficiency of steam. The key to its use is the establishment of a relationship between specific volume and the average pressures for various wet steamfloods. This relationship was determined by a series of experiments and is presented in the discussion on results.

CHAPTER IV

EXPERIMENTAL APPARATUS AND MATERIALS

Several types of experiments were performed in this investigation. Therefore a basic requirement of the apparatus was versatility. The major components of the apparatus and the materials used are discussed in this chapter.

Experimental Apparatus

The core holder assembly was the main component of the apparatus. Other major groups were heating units, liquid-metering units, and monitoring units.

Core Holder Assembly

The core holder assembly (Figure 4) is based on a Hassler-type core holder. Annulus pressure to the rubber sleeve surrounding the core is used to insure that fluid flows through the core.

The outer pipe shell has threaded ends and is constructed of Monel steel. End plates of Monel steel abut the ends of the consolidated core and are held in place by steel clamps over the Viton-A rubber sleeve enclosing the

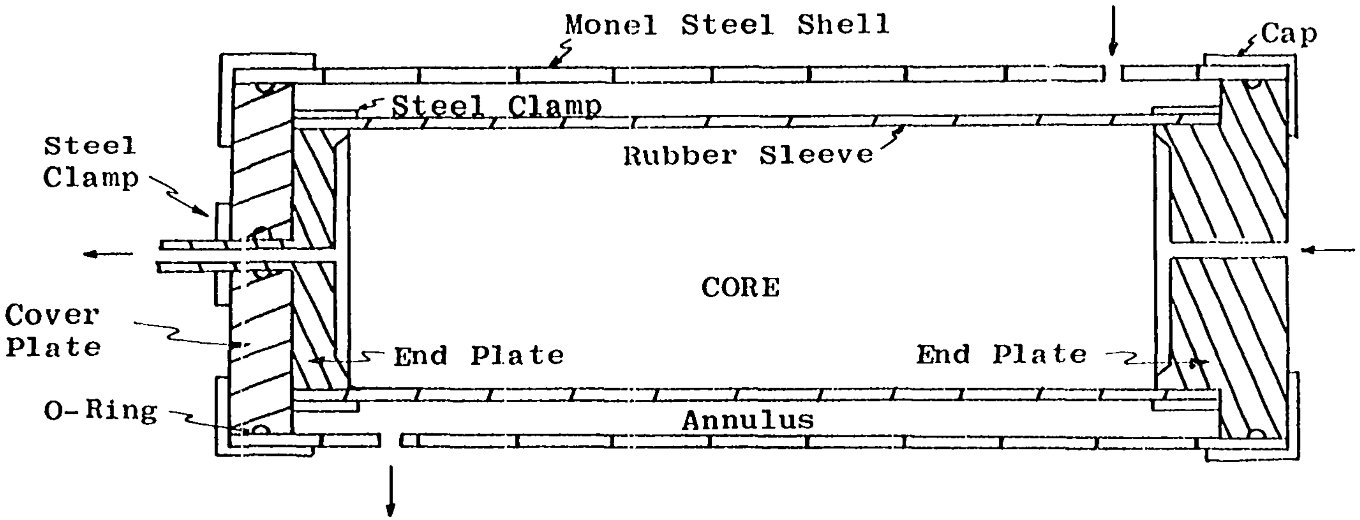

FIGURE 4 CORE HOLDER ASSEMBLY

core. As shown on Figure 4 these plates are flaired next to the core to permit fluid entry and exit from the entire face of the core. The lower end plate also contains O-rings of Viton rubber to provide the annulus seal. The upper end plate contains no O-rings but has a cover plate which fits over the upper end-plate stem. This plate cover has inside and outside Viton-A O-rings to seal the annulus. With this type of arrangement, core size can be varied by varying the stem length on the upper end plate. In the present study a 22-inch core was used which is the maximum length the core-holder assembly can handle. Maximum core diameter is 2 1/8 inches. To vary core diameter would require replacing both end plates, rubber sleeves, and clamps.

Upper- and lower-caps screw onto the shell and provide support for the longitudinal stress encountered under pressure. A pressure limitation of 500 psia with a temperature limitation of 500°F were established by the O-rings which tend to harden with use. Periodic replacement was required for trouble-free operation.

Good seals could be provided on the core by the rubber sleeve with a minimum differential pressure of 100 psi. This is an experimental value that was substantiated by good grain embossment on the inside of removed rubber sleeves and overnight pressure tests. Leads from the two pressure taps in the core were brought out of the core through the stem in the upper end plate.

Heating Apparatus

The heating units consisted of two steam generators which were constructed of electrically-heated, stainless-steel tubing and three commercially obtained flexible heating tapes. The two steam generators were used to independently supply heat to the annulus and to the core. Voltage was manually controlled on the two generators by two powerstats which were connected in series with a 3.58:1 step-down transformer for greater powerstat sensitivity. A 0-140 volt, 50-amp powerstat was used to control the steam generator for the annulus heat requirements while a 0-115 volt, 15-amp powerstat was used to control the heat requirements for steam injection into the core.

The three heat tapes were controlled by 7½-amp powerstats. These tapes were used for flexibility in heat loss control. One tape was located on the line from the core generator to a junction where steam and cold water were mixed. Another tape was placed between the mixing junction and the core inlet while the third heat tape was placed around the core holder shell. All three tapes were inside of the Urethane insulation used.

The primary function of the two tapes from the steam generator to the core inlet was to permit heat loss evaluation from the steam generator to the core inlet with superheated steam.

The main purpose of the large heat tape around the core holder was to permit rapid attainment of adiabatic conditions on the core by cutting down on heat loss from the annulus. The control of this heat tape in conjunction with the control of the temperature of the annulus inlet was the key to obtaining the desired adiabatic conditions on the core.

Liquid-Metering Apparatus

The liquid-metering units consisted of a nitrogen-loaded pressure tank containing water, a metering pump and two rotameters with needle-valve control. The pressure tank was loaded with de-ionized water and then pressured with nitrogen which was separated from the water by a 2-inch layer of oil. Water was metered from this tank by the rotameters without the pressure surges from a pump. This system provided an excellent maintenance-free method of obtaining the required constant water rates and permitted very steady pressure readings.

A single-simplex metering pump provided the large mass rates required to the annulus. Water from this pump went to a steam generator where it was heated to the desired temperature. Sufficient back pressure was maintained on the annulus so that at no time was steam permitted in the annulus.

Pressure and Temperature Equipment

All pressures were monitored by pressure transducers while all temperatures were monitored by thermocouples. The location of these units is shown on Figure 5 which is a schematic of the experimental equipment.

A Validyne Model DP15 variable-differential transducer was used. It combined accuracy and resistance to shock over the wide range of differential pressures encountered in this investigation. Although replaceable diaphrams from 0.1 to 3000 psid are available, only 5-psid, 50-psid and 100-psid diaphrams were used. Calibration of the 5- and 50-psid diaphrams was by manometer. An additional check with a dead-weight tester of the 50-psid diaphram gave excellent agreement. The 100-psid diaphram was calibrated with a dead-weight tester. Recalibration was performed periodically but no problems developed.

Readout of the differential transducer was on a Validyne Model CD12 Transducer Indicator. Direct digital readout to 1000 scale units was available and used with excellent results and repeatability.

Four Consolidated-Electrodynamic pressure transducers were used to monitor various pressure points in the system and were read with a multichannel pressure recorder. Periodic recalibration checks showed no significant drift. A shift in the recorder scale was made to increase accuracy of readout by using as full scale only

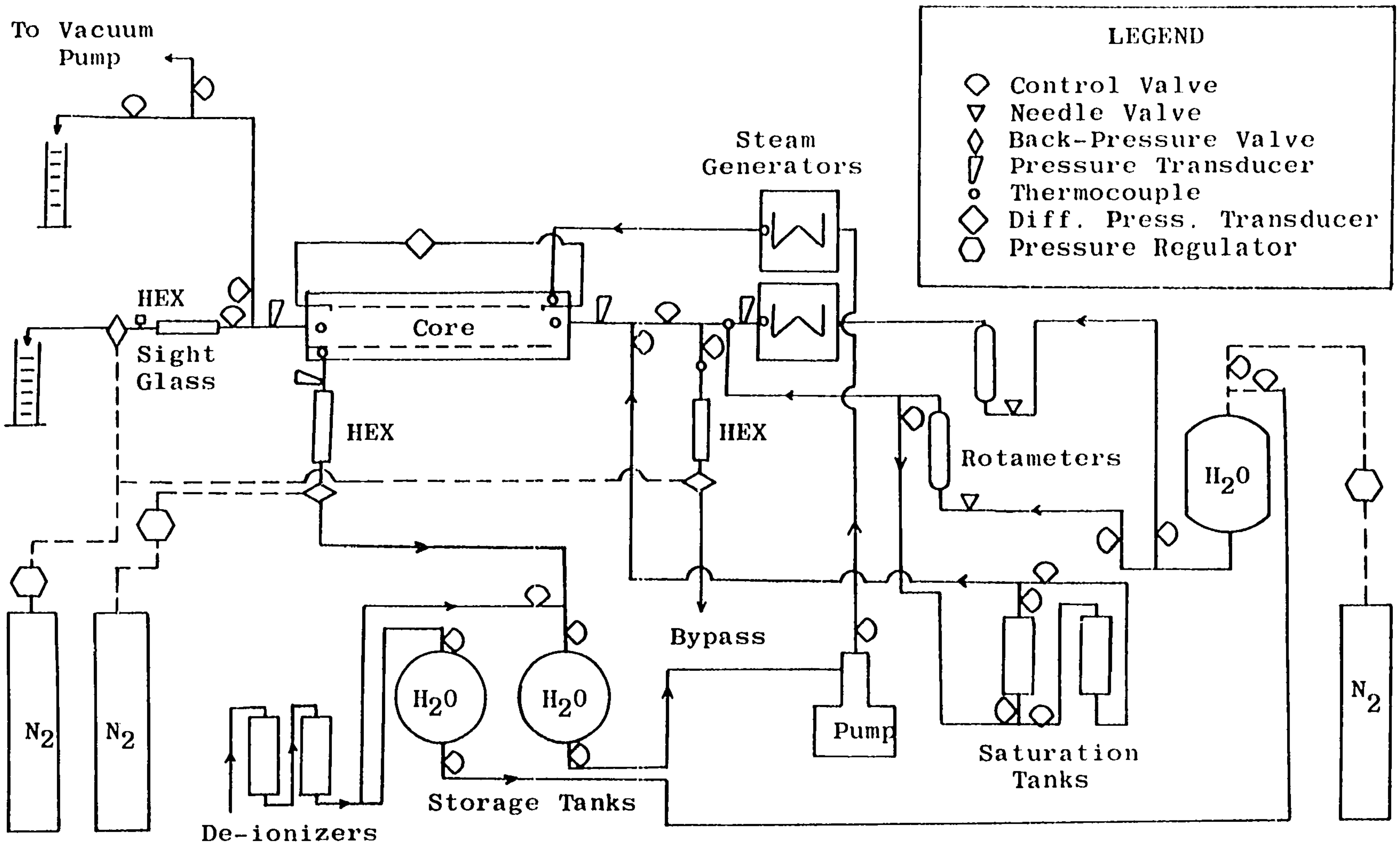

FIGURE 5 DIAGRAM OF EXPERIMENTAL APPARATUS

$\frac{1}{2}$ of the full mv range of the three 500-psi and one 1000-psi transducers. Overall accuracy of these transducers and the differential transducer was $\pm\frac{1}{2}\%$ of the best straight line through the calibration data.

Temperature was monitored by iron-constantan thermocouples and recorded on a multichannel temperature recorder. These temperatures when used with the corresponding pressures from the pressure recorder checked quite closely with the temperatures for saturated steam from the steam tables. Accuracy of temperature recorded was $\pm 1^{\circ}F$.

Constant back-pressure on the core and annulus was provided by Grove Mity-Mite, dome-loaded valves which were rated at $150^{\circ}F$ maximum and 2000 psia. Dome pressure was provided by nitrogen. Counter-flow heat exchangers were constructed and installed in front of the valves to reduce the effluent from the core assembly to below $150^{\circ}F$. Even with this heat protection, diaphrams in the valves had to be replaced at a higher frequency than anticipated—apparently due to solvent and oil reaction.

Auxillary Equipment

Two stainless-steel saturation tanks were used for the oil and cleaning fluids used. Displacement from these tanks was by water from the nitrogen pressure tank although part of the time a displacement pump was used. Prior to oil saturation a regular vacuum pump was used to assist in removing any air from the core.

In order to determine if emulsions were forming in the core or through the back-pressure valve, a sight glass was constructed and placed in front of the back-pressure valve. Construction was from pressure-rated pyrex boiler glass with Viton-A rubber bushings in the absence of teflon. Initially the sight glass was placed in front of the heat exchanger but after extended use the bushings started to leak. No more trouble developed after placing it behind the heat exchanger.

Materials

Outside insulation for the core holder, manifolding, and steam lines was with commercial Urethane. This material has a density of 1.9 lb/ft^3 and a thermal conductivety of 0.15 Btu/ft^2-hr-^{o}F.

The porous media used in these experiments were Boise and Berea consolidated sandstones. A block of Boise sandstone was obtained from the Boise Idaho quarry and a core was machined to an average diameter of 2.10 inches. Final length was 21.9 inches. The Berea core which had an average diameter of 2.1 inches and a length of 21.9 inches was obtained through the courtesy of Pan American Research in Tulsa, Oklahoma. Table 1 gives the mineralogical content of these rock types as reported in the literature.

Table 1

MINERAL CONTENT BY PERCENT WEIGHT

OF BOISE AND BEREA SANDSTONES

	Berea[45]	Berea[44]	Berea[46]	Boise[45]	Boise[44]
Quartz	85	65	85	45	40
Feldspar	5	10	5	45	35
Carbonates	1	*	1	--	**
Clays	7	*	7	9	**
Fe-Ti Minerals	2	*	2	1	**

* Calcite, Sericite & Clay in unreported amounts

** Clay, Sericite in unreported amounts

After each core was cut and machined to the required dimensions, a slot was cut the length of the core with a diamond saw. Small holes were then drilled about 4½ inches from each end in the bottom of the slot. Stainless-steel tubing of 1/16 inch O.D. was then inserted in the holes and bent to stay in the slot of the core so that the two pieces of tubing lay parallel and both came out one end of the core.

Heat transfer cement was placed in the slot above and below the tubing to restore the circular contour of the core. The core was then placed in the oven at 350°F to dry the cement which does not set at room temperature. After removing from the oven, a metal file was used to shape the cement contour so that a good seal could be obtained when the core was inserted in the rubber sleeve and pressure applied to the annulus.

Steamouts were used to clean and stabilize the core before any data could be taken. All porosity and property measurements made on the two cores and on core plugs are reported in the experimental results section.

The oil selected for this study was Phillip's Soltrol 170 which is composed of virtually 100% isoparaffinic hydrocarbons. Aromatic content is nil. Basis for this oil's selection was its high gravity (51.2^{o} API at 76^{o}F) and high initial boiling point (424^{o}F). Figure 6 shows the effect of temperature on the viscosity of the oil. Measurement of this data was obtained with a Cannon-Fenske Viscometer in a hot water bath. The viscosity of the oil decreases from 2.55 cp at 78^{o}F to an extrapolated value of 0.33 cp at 382^{o}F. This is only slightly less than an eight fold decrease in viscosity for a 304^{o}F temperature increase. Therefore as desired in these experiments, viscosity reduction played no significant role in the displacement process.

Figure 7 shows the effect of temperature on the density of the oil. This density decreased from 0.7750 g/cc at 76^{o}F to an extrapolated value of 0.66 g/cc at 382^{o}F. Figure 8 shows the ASTM distillation curve for Soltrol 170

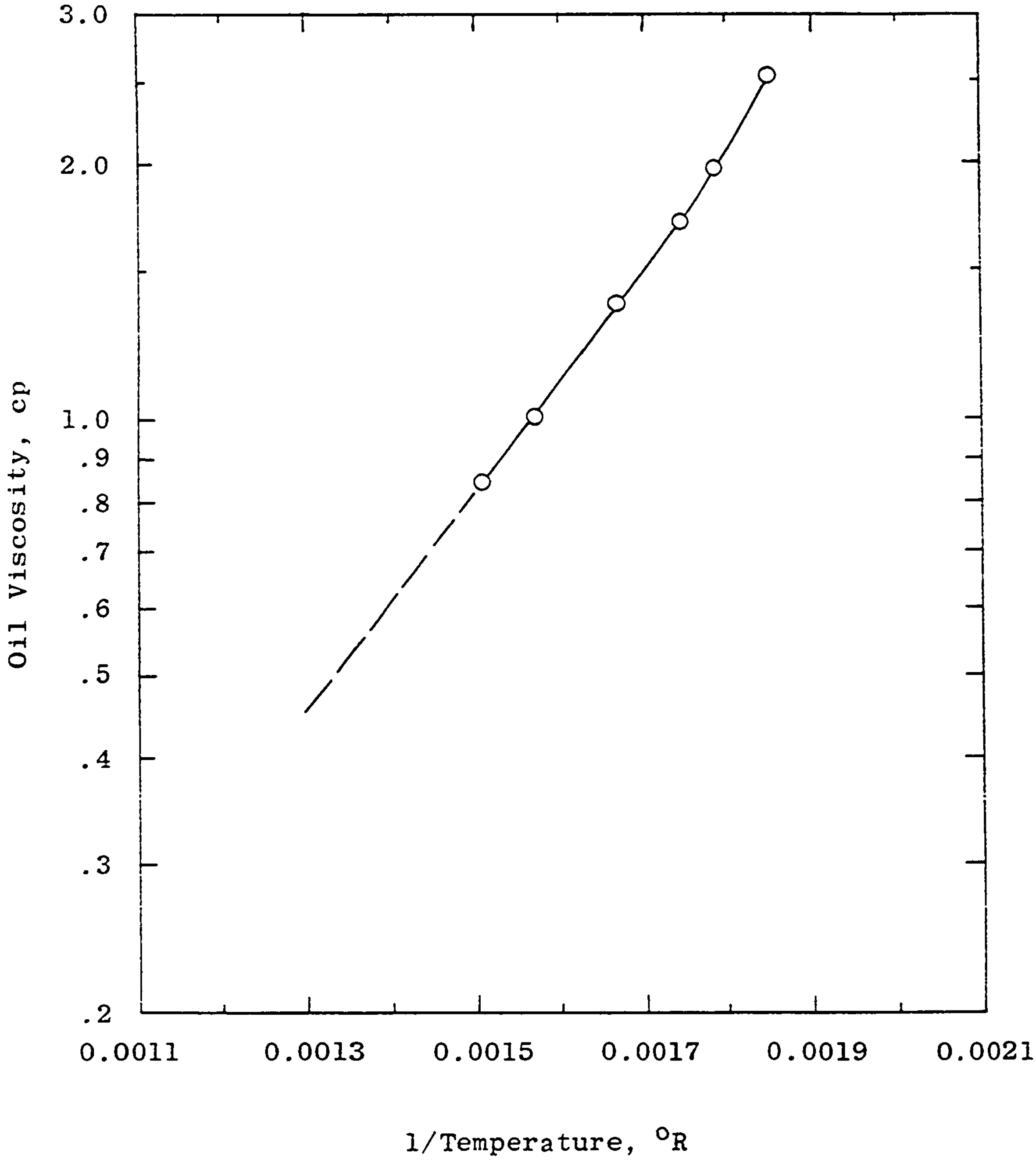

FIGURE 6 OIL VISCOSITY VS TEMPERATURE FOR SOLTROL 170

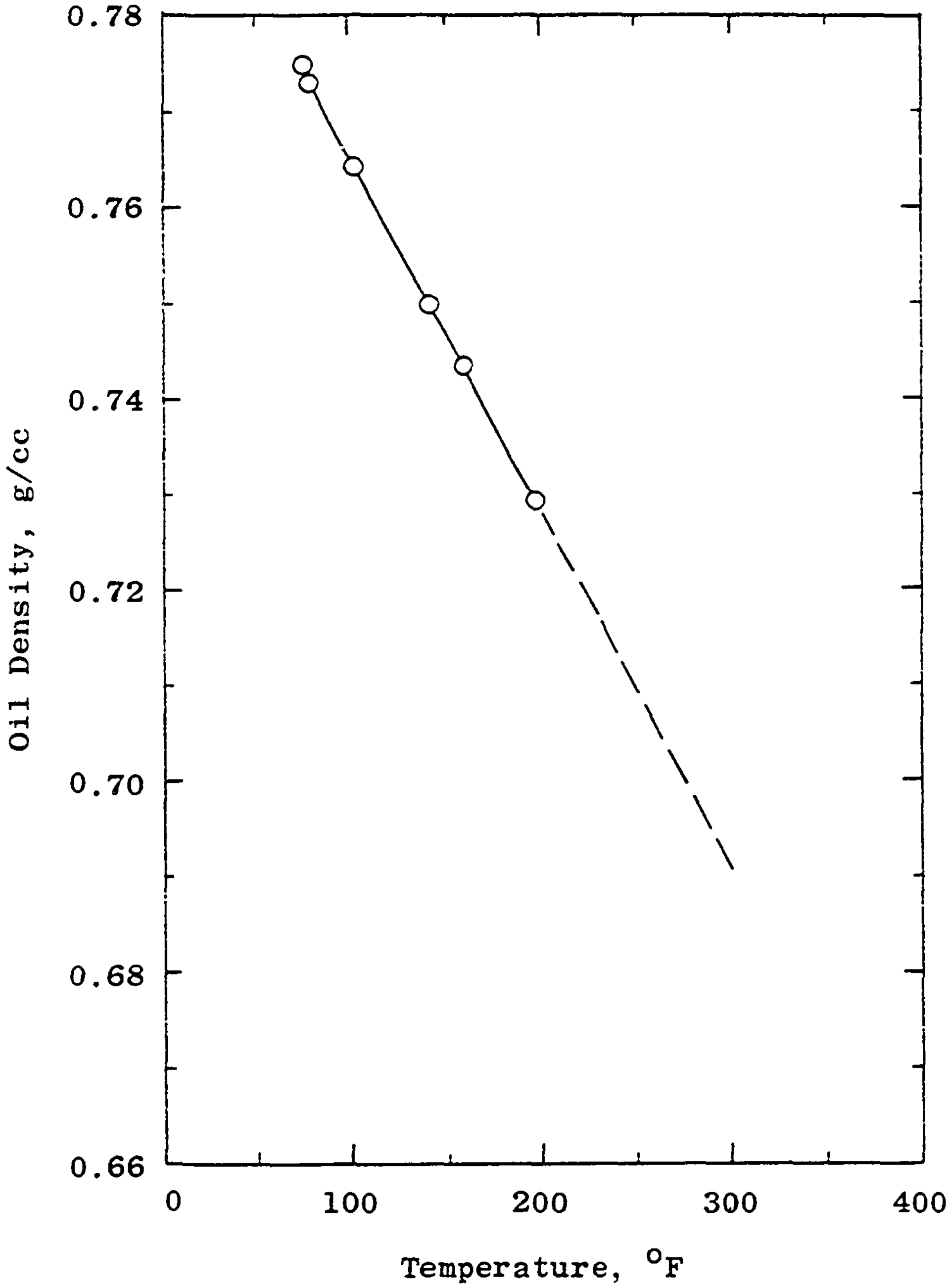

FIGURE 7 OIL DENSITY VS TEMPERATURE FOR SOLTROL 170

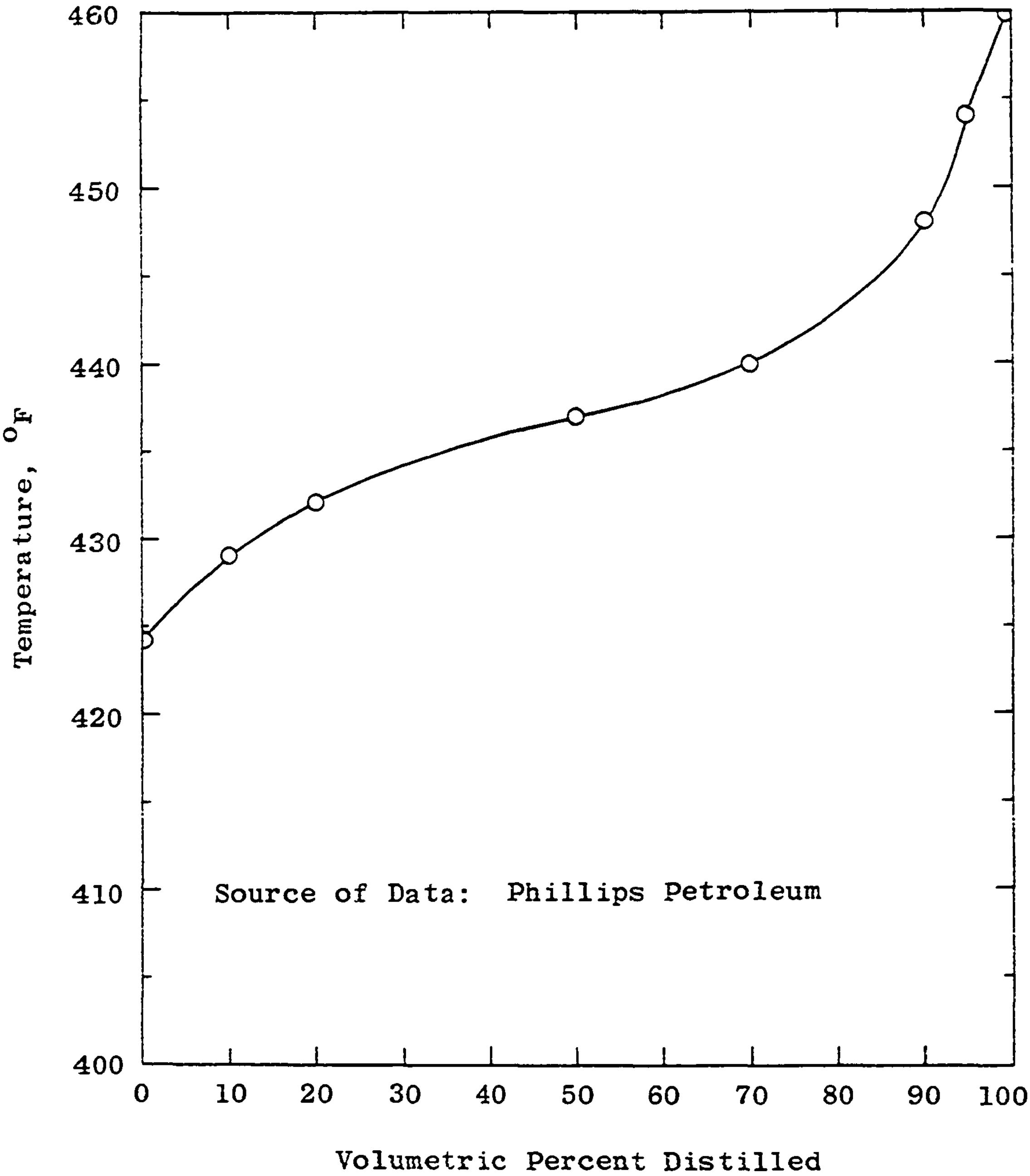

FIGURE 8 ASTM DISTILLATION CURVE FOR SOLTROL 170

which is based on data furnished by Phillips Petroleum Co. As the maximum injection temperature in these experiments was 385°F, the boiling point curve was well above the run temperatures.

CHAPTER V

EXPERIMENTAL PROCEDURE

Separate experimental procedures were required for the relative permeability, water mobility and oil recovery experiments. Supplementary procedures for initial saturation, for preparation of moist steam and for experimental heat-loss data are also presented in this chapter.

Initial Saturation

Prior to any of the experiments, the core with 150 psi annulus pressure was saturated with de-ionized water. Using separate saturation lines, a vacuum was applied to the core outlet while the water rate at the core inlet was adjusted to develop a small inlet injection pressure. Injection was continued in this manner to remove any air from the core and the lines and manifolding. At this point the core could be isolated from the saturation lines and steam mobility or absolute permeability runs made.

If oil saturation was required, then the annulus pressure was increased to 350 psia and oil was displaced from a stainless-steel saturation tank with water until a residual water saturation existed in the core. This residual water saturation, which was determined by material balance, approached that of an irreducible water saturation.

Preparation of Moist Steam

Steam of different qualities was obtained by mixing known mass rates of superheated steam and cold water according to mass-enthalpy balance requirements. The enthalpy of the injected steam is given by

$$H_t = \frac{M_{cw}H_{cw}}{M_t} + \frac{M_{shs}(H_{shs}-HL1)}{M_t} - HL2 \qquad (6)$$

where HL1 and HL2 are experimentally determined heat losses. The steam quality can then be calculated from equation (2), here redefined as equation (7):

$$X = \frac{H_t - H_{sw}}{H_{vap}} \qquad (7)$$

Isothermal moist steam at 382°F (200 psia) was injected into the core in this study. This required superheated steam of 475-600°F at the steam generator which was mixed at a mixing junction with cold water and then sent through a bypass. Only after the system had stabilized with the desired flow rates of cold water and superheated steam was the quality steam ready for injection into the core under isothermal conditions.

Heat Loss Data

The required heat loss data in the mass-enthalpy balance used to calculate inlet steam quality was determined experimentally. Single-phase flow was required to obtain the heat loss from the steam generator to the mixing junction (HL1) and then from the junction to the core inlet (HL2).

A setting on the powerstat controlling the heat tape on the line from the junction to the core inlet was determined experimentally. This setting, which was used on all runs, permitted superheated steam at the core inlet when the tape from the generator to the junction was in operation. The heat tape from the generator to the junction was not used during the runs. It was only turned on when superheated steam was needed from the junction to the core inlet for heat loss data. Graphs of enthalpy vs mass rates were constructed for each of the lines and periodically revised or rechecked as required.

Equating change of enthalpy to heat loss was made with the assumption of constant pressure, as required by thermodynamic principles, from the steam generator to the core inlet. A negligible pressure gradient existed because of the short distance (< 3 ft) between the steam generator and the core inlet.

In order to calculate exit steam quality from the core under steady-state conditions for some of the experiments it was necessary to obtain heat loss data for the annulus. The procedure was to establish adiabatic conditions between the core and the annulus by matching core inlet-outlet temperatures to annulus inlet-outlet temperatures for different annulus flow rates. An application of the first law of thermodynamics could then be used to calculate the heat loss under steady-state conditions. Appendix F shows the calculation and application of the annulus heat-loss data to calculate exit steam quality.

Steam Mobility Experiments

A requirement of the steam mobility experiments was the establishment of adiabatic conditions on the core. By matching the temperature gradient in the core with the annulus temperature gradient, a good average steam quality could be obtained. For the highly permeable Boise core, the pressure drop due to flow was so low that essentially constant quality was obtained throughout the core. The larger pressure drop in the Berea caused an increase in steam quality at the core outlet in conformity with Figure 3.

The use of a large heat tape on the annulus reduced the matching of the outlet temperatures of the core and annulus from hours to minutes of operation. To insure that the temperature drop in the core was entirely due to pressure drop, the annulus outlet temperature was adjusted to exceed the core outlet temperature by $1^{o}F$. With the correct temperature gradient stabilized as desired, the differential pressure was recorded.

Mass rates were then changed to determine a new quality of steam injected and the annulus gradient again superimposed over the new temperature gradient in the core. This sequence of quality change, temperature and pressure stabilization continued over the desired quality range. If oil was in the core, then observance of the core effluent was required to note any residual oil reduction due to quality change.

The hot-water mobility experiments were run in the same manner except that isothermal, adiabatic conditions were required throughout the system. To maintain both inlet and outlet temperatures of the core and annulus at one value over a period of time was difficult. Pressure readings over a period of time showed temperature variation to have little effect on the pressure differential.

Relative Permeability Experiments

Both cold and hot waterfloods were run on the Boise and Berea cores to calculate relative permeability curves.

For the cold waterflood, no artificial back pressure was applied to the core so that fluid production was against atmospheric pressure. Therefore once the saturation procedure was complete then water at the desired injection rate was introduced into the core. Oil effluent was collected until water breakthrough then oil and water were collected on an interval basis and ΔP recorded.

The hot waterfloods were similar to the cold waterfloods except a back pressure on the core was required to prevent water vaporization at the desired flood temperature. Isothermal conditions were established in the core annulus at the desired temperature of hot-water injection into the oil-saturated core. Hot water was circulated through the by-pass until it had stabilized at the desired injection temperature. The pre-injection expansion volume of the oil was recorded. After injection of the hot water, the procedure was the same as the cold waterflood. Injection in both the cold and hot waterfloods continued until no more oil could be detected in the effluent by visual examination.

Oil Recovery Experiments

Control of the 382^{o}F injection temperature of the wet steam into the core was maintained by regulating the back pressure on the core. Simultaneously with the injection of steam, the annulus inlet temperature was raised by turning on the powerstat controlling the annulus steam generator. Within minutes the annulus inlet temperature was the same as the core inlet temperature.

The purpose of this annulus heating procedure was to permit steam breakthrough from the core over a quality range in a reasonable length of time. Injection and annulus rates were experimentally determined for these conditions. Average heat loss from the core could be experimentally determined (see Appendix G) instead of a preset value as calculated from insulation of given characteristics. The only serious drawback to this type of procedure is preheating of the core. This occurred in these experiments but it had a minor effect on the results because a high gravity, non-distillable oil (at the experiment conditions) was used.

Injection of steam after breakthrough was continued until no additional oil could be detected visually in the core effluent. Then the annulus heat tape was turned on and adiabatic conditions were established on the core. Injection was continued until no more oil in the effluent was observed.

In the oil recovery experiments with the Berea core, a constant, isothermal, steam-injection temperature of approximately 382^{o}F was difficult to maintain. The large pressure drop through the Berea produced a sluggish response at the core inlet to the back-pressure regulator. Whereas the inlet temperature of the injected steam could be maintained within 1^{o}F with rapid response to back-pressure adjustment for the Boise sandstone, constant monitoring of the day-long Berea runs was required to stay within 2^{o}F.

Another adjustment was required on the Berea core. Control over inlet temperature could not be maintained at the 15 cc/min injection rate used on the Boise. With injection rates of this size, the inlet pressure and thus temperature continued to build beyond the desired 200 psia— even with the outlet pressure at atmosphere pressure during initiation of the flood. As a result the injection rates were lowered to approximately 9 cc/min except for the lowest quality evaluated of 8%. In this run an injection rate of 11.3 cc/min was used, but the increase was in cold water rate to obtain the low quality required. A minimum water rate through the steam generator had previously been arbitrarily set at 5 cc/min for equipment protection. As Table B-11 shows in Appendix B, a water rate of 5 cc/min to the generator out of a total water rate of 9.5 cc/min would only lower the injected quality to 29.3%. A combination of less than 5 cc/min to the steam generator and an increase in cold water rate was required to obtain an injected quality as low as possible. The equipment was monitored quite closely during this run but no difficulty developed and the required control over inlet injection temperature was maintained.

The water injection rate in the annulus used for the Boise core also proved too large for the Berea core. Therefore it was lowered from an average of 85 cc/min to an average of 65 cc/min. Even with this new lower annulus rate, most quality runs transferred heat from the annulus to the core.

Core Cleanout

After completion of experiments containing residual oil saturation, several volumes of Chlorothene (CH_3CCl_3, density 1.437 g/cc at 20°C, IBP 74-76.5°F at 14.7 psia) were injected into the cool core. Several pore volumes of cold water were then injected into the core and this in turn was followed by several pore volumes of high quality steam. After cooling the core was then ready for the initial saturation procedures previously described. This cleanout procedure was first used on the Boise core and had been used satisfactorily with crude oil.[18,49]

Some surprising results were obtained when the Chlorothene was used to clean out the residual Soltrol 170 oil. The cleaning action of this combination under displacement by high quality steam was so efficient that in short order the water permeability of the core was increased from 3.5 darcy to about 10.0 darcy. This was quite desirable as a wide spread in permeability between the Boise and Berea sandstones was needed, however this cleanout procedure was shortly abandoned due to operational difficulties. The core was dismantled from the core-holder assembly and visually inspected because of the large sand content in the effluent and because the odor and color of the effluent suggested that the core sleeve was being attacked. Other than odor the sleeve appeared undamaged. Some of the heat transfer cement appeared to have softened in the process so this was replaced with new cement and the core again baked at 350°F for 24 hours. After filing, the core was mounted in a new sleeve and re-installed in the core holder.

In the new cleanout procedure, several pore volumes of tertiary butyl alcohol were injected into the core to remove the residual Soltrol 170. The alcohol was removed by several pore volumes of cold water. Cleanout results were satisfactory as substantiated by the results of a following high-quality steamflood.

CHAPTER VI

PRESENTATION AND DISCUSSION OF RESULTS

Several types of experiments were required in this investigation. They are grouped into absolute permeability, relative permeability, steam mobility, and oil recovery experiments. Results from each group are presented and discussed separately, however results from all the experimental groups are brought to focus in the discussion of the oil recovery experiments.

Absolute Permeability Experiments

The initial cleanout procedure on the Boise sandstone increased the permeability from 3.6 darcys to about 10 darcys at room temperature. After introduction of oil the permeability stabilized at approximately 8.1 darcys. Previous work[49] had suggested an effect of Chlorothene on permeability but not of the magnitude obtained in these experiments.

Although the large increase in permeability was believed to be due to the combination of the high-gravity Soltrol 170 and Chlorothene in the steamouts, a separate study was made to verify this. Table 2 gives the air permeability of several 3/4-inch diameter Boise and Berea core-plugs that were treated.

Cores were placed in the Chlorothene soak for 12 hours at room temperature and then oven dried at 100°F for 24 hours. The purpose of the soak was to determine if any chemical reactions occurred with the sandstone clays which would affect the measured core properties. Baking of the cores was done at 350°F for 48 hours to determine if heat would effect the clays.

A comparison of permeability values for cores 1-5 suggests that while baking did not appear to affect the porosity values, it may have slightly increased the permeability. These plugs were cut from excess machined portions of the 22-inch cores and parallel to the core axis.

Plugs 6 and 7 were cut from the 22-inch Boise core at the conclusion of the experiments. Plug 6 was cut parallel to the core axis while plug 7 was cut at right angles to the core axis. Table 2 shows not only the increased permeability which developed but also suggests that some directional permeability developed. In addition the effective porosity appeared to have increased slightly.

Plug 8 was cut from a different section of Boise. Its treatment and inclusion in the table was to show that other than cleanup, the Chlorothene had no affect on the core permeabilities.

TABLE 2

AIR PERMEABILITY OF BOISE AND BEREA CORES

Core No.	Sandstone	Chlorothene Soak	Bake	Steam Out	Effective Porosity	Air Permeability, md
1	Berea	X			0.224	935
2	Berea		X		0.223	952
3	Boise	X			0.282	3590
4	Boise		X		0.289	3870
5	Boise	X			0.280	3790
6	Boise			X	0.299	9000
7	Boise			X	NM	7480
8	Boise	No treatment			NM	2860
8	Boise	X			NM	2880

NM = not measured

Another Boise plug was cut from a core used in an earlier experimental study with steam and crude oil. Although the core had been cleaned with Chlorothene, an air permeability of only 1800 md was obtained. Apparently the crude oil reduced the solvent action of the Chlorothene on the rock properties to a minimum. The final air permeability was only about half that of the initial air permeability on the present Boise rock used.

Ozen[26] reported permeability reduction problems with Berea sandstone while running steamflood tests with a Bradford crude. Permeability decreased from 220 md to 80 md at the end of 6 floods and was essentially plugged at the end of 9 runs. He felt this was "partly due to hydration of clays and partly due to corrosion at the inlet, which led to the plugging of the face of the core." In order to regain permeability Ozen injected 0.1 pore volume of 15% HCl into the steam filled core. After a few minutes the HCl was flushed out but the permeability of the core only increased to 80 md. For the last six runs permeability only decreased to 60 md.

A variable absolute permeability is unacceptable for comparative recovery experiments so a very close permeability history was kept throughout the present experimental work with the Berea sandstone. The history is shown in Table 3. As expected the permeability did initially decrease but stabilized quite well. The maximum variation

TABLE 3

PERMEABILITY HISTORY OF BEREA SANDSTONE

Occurrence	Water Permeability, md.
During initial tests and cleanup	642-679
Measured after core cleanout for the following runs.	
Cold waterflood No. 1	410
Hot waterflood No. 1	326
Steamflood No. 1	360
Steamflood No. 2	353
Steamflood No. 3	341
Steamflood No. 4	363
Steamflood No. 5	373
Steamflood No. 6 (repeat of run No. 2)	387
After hot-water mobility and steam mobility runs	527

for the steamfloods was from 326 md to 387 md. After the hot waterfloods and the steam mobility experiments, the permeability only increased to 527 md. Therefore the original permeability was never restored.

The lack of any unexpected shift in permeability suggested that no significant rock property changes had occurred in the Berea and so an extensive study was not made as with the Boise sandstone. Table 2 shows the air permeabilities of two Berea sandstone plugs. A plot of the air permeabilities for the 1-Berea core against the reciprocal mean pressure gave an extrapolated value at infinite mean pressure of 685 md. This value was in good agreement with the water permeability of 679 md measured on the full core in place as shown in Table 3.

The effect of temperature on the absolute permeabilities of both the Boise and Berea sandstones appeared slight. The trend of increased permeability of the Boise sandstone appeared to parallel that of the Berea sandstone but data variation was too large for any definite conclusions. A rate of change of permeability of 0.23 md/$^{\circ}$F is estimated for the Berea from the data in Figure 9.

Steam Mobility Experiments

One of the objectives of the hot water and steam mobility experiments was to investigate a suggested undersaturated hot water-low quality steam mobility discontinuity.[18] Such a discontinuity suggests that oil displacement by undersaturated hot water will be more efficient than oil displacement by higher quality steam but less efficient than lower-quality (< 15%) steams. In the present investigation no significant mobility discontinuities were observed for the Boise or Berea sandstones.

Figure 10 shows the comparison of the mobility of hot water and steam mobility in Boise sandstone. At ef-

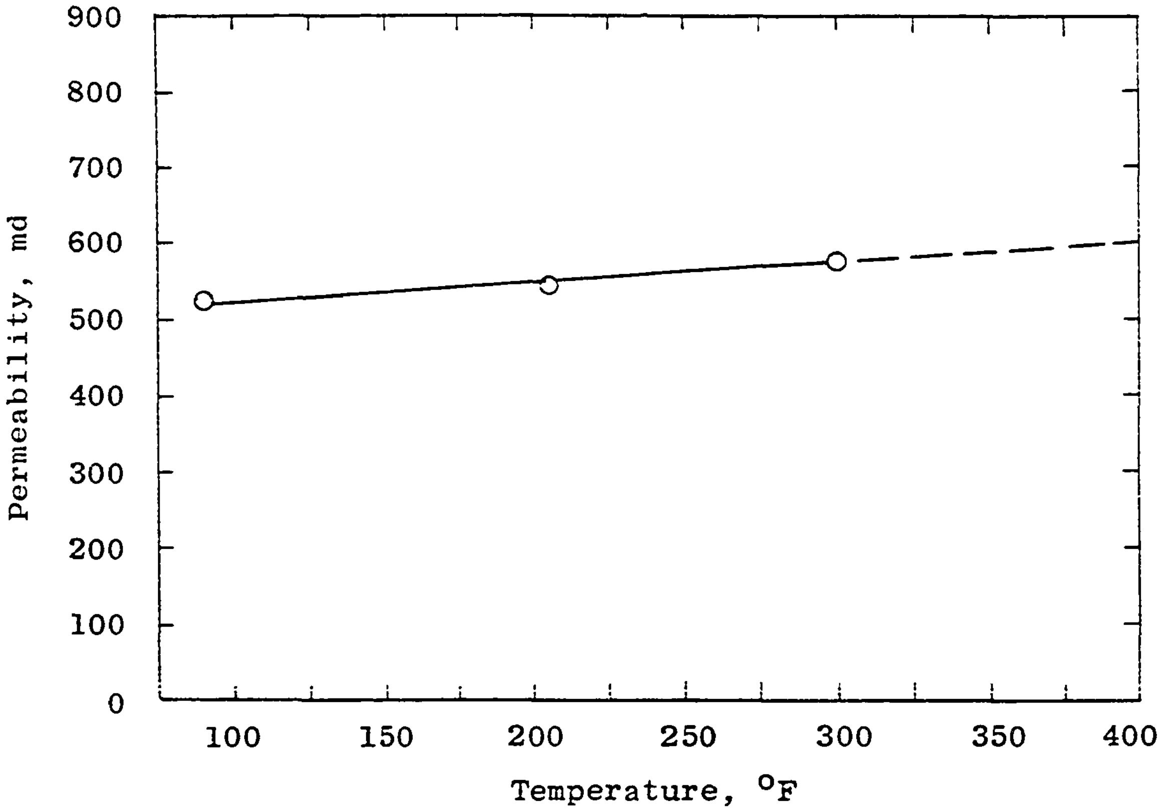

FIGURE 9 EFFECT OF TEMPERATURE ON ABSOLUTE PERMEABILITY OF BEREA SANDSTONE

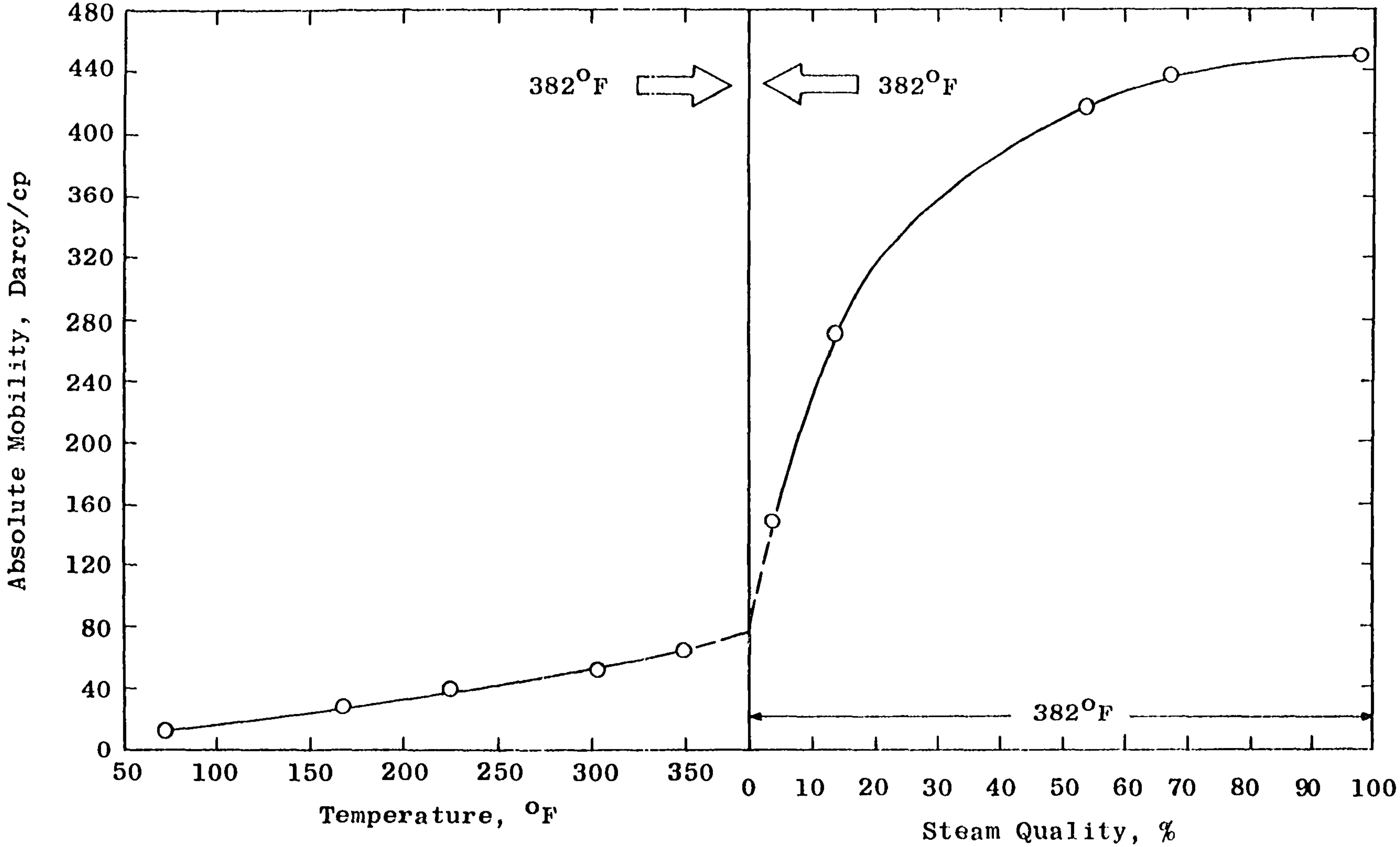

FIGURE 10 COMPARISON OF ABSOLUTE MOBILITIES OF HOT WATER AND WET STEAM IN BOISE SANDSTONE

fective mobilities of 75-80 darcys/cp the extrapolated steam and liquid water mobilities appear to be the same. This figure shows considerable curvature as steam mobility increases with steam quality increase. In Figure 11 the curvature is still apparent and shows the effect of a fairly constant residual oil saturation of 4.5% over a spectrum of steam qualities. These curves are the result of two continuous runs with decreasing quality and neither this curvature nor parallelism remained for long. The principle value of Figure 11 is that it shows residual oil saturation has a significant effect on steam mobility. Because of its measurement during an apparent change in mobility behavior, no valid conclusions can be made.

Both curvature and uniformity were lost in subsequent experiments. Figure 12 shows the sequence of steam mobility changes prior to final stabilization and is a history of the potential problems with this type of data. These experiments were run before the regular steam recovery experiment runs but the latter line (run 3) held remarkably constant. At the completion of all recovery runs, a repeatability check made on the upper two points of run 3 had a maximum deviation of 4.8%. This contrasts sharply with initial studies at the beginning of this investigation where serious doubt existed as to obtaining any meaningful, repeatable, steam mobility data.

The loss of curvature on the steam mobility line is

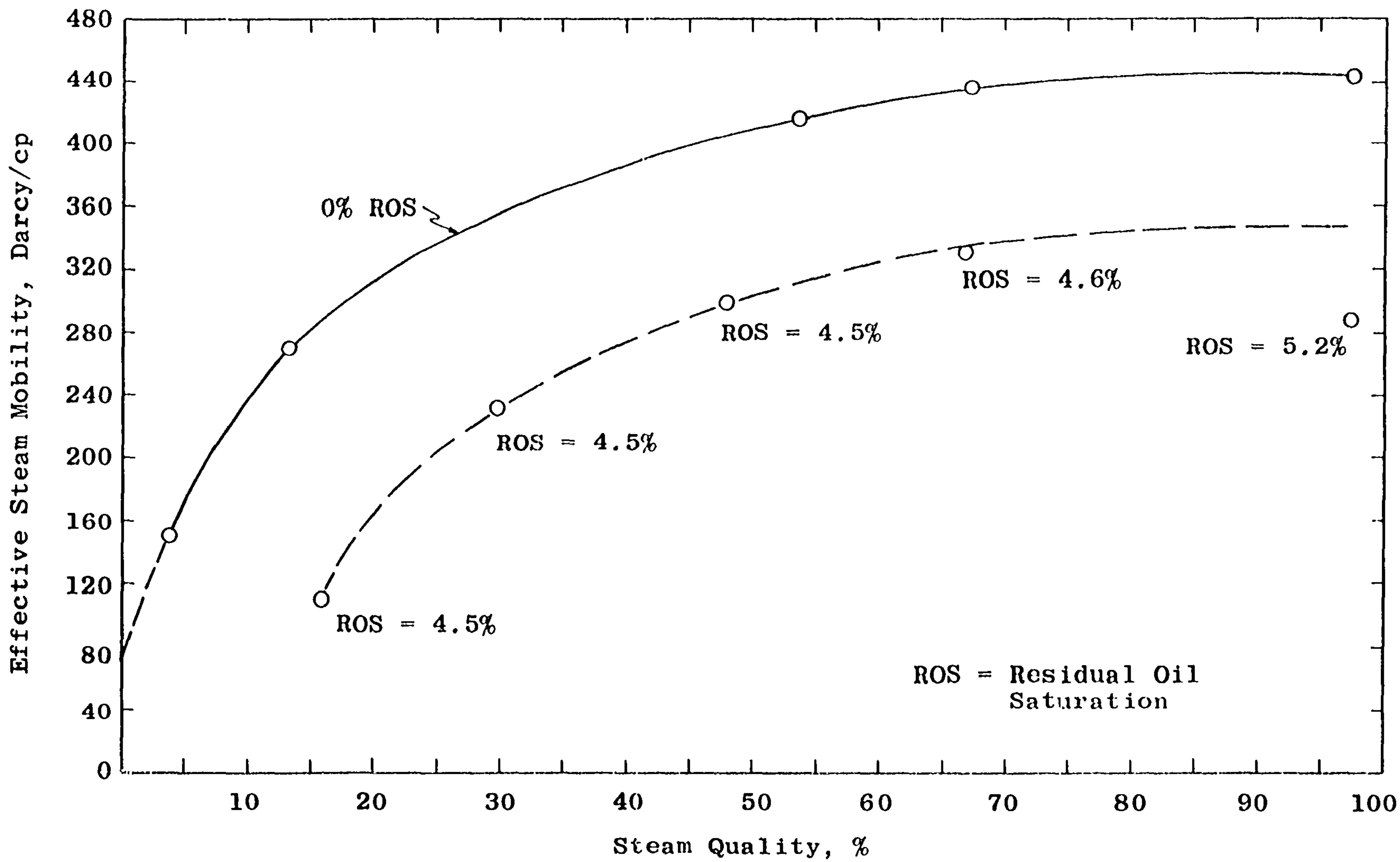

FIGURE 11 EFFECT OF OIL SATURATION ON THE MOBILITY OF WET STEAM IN BOISE SANDSTONE FOR CONTINUOUS QUALITY REDUCTION RUNS

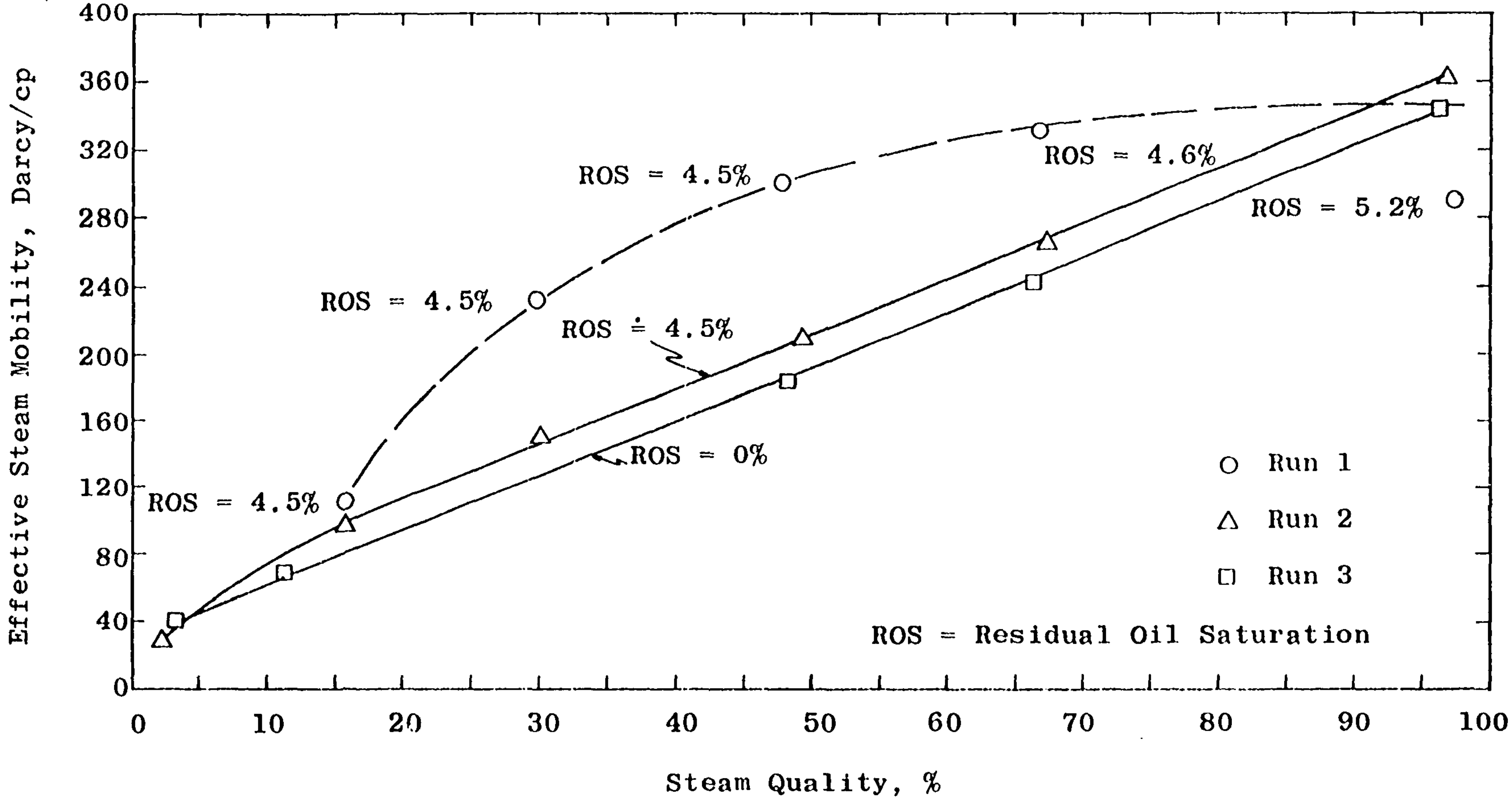

FIGURE 12 SEQUENCE OF STEAM MOBILITY CHANGES PRIOR TO FINAL STABILIZATION

believed to be caused by changing rock wettability. After baking the core for the second time (as explained in the procedure section) and establishing that a large permeability existed, the comparative mobility runs for hot water and steam were made before introduction of oil a second time into the core.

The effect of residual oil saturation (ROS) on effective mobility of wet steam in Boise sandstone is also shown in Figure 13. These ROS points however are individual measurements taken at the end of the oil recovery runs. A point to note in this figure is that residual oil saturation does have an influence on the effective steam mobility but this influence appears to decrease with quality.

Similar liquid mobility studies are shown in Figures 14 and 15 for Berea sandstone. Data for these curves was obtained at the conclusion of the oil recovery experiments. Therefore no change in wettability problems occurred although a slight curvature persisted for the line of zero percent, residual oil saturation.

The curves of steam mobility and liquid water mobility appear to be continuous and meet at about 4.6 darcy/cp. This is about 1/15 the mobility of saturated water at 382°F in the Boise sandstone. As with the Boise sandstone no significant mobility discontinuity appears to be present.

The effect of residual oil saturation on effective steam mobility in Berea sandstone is shown in Figure 15.

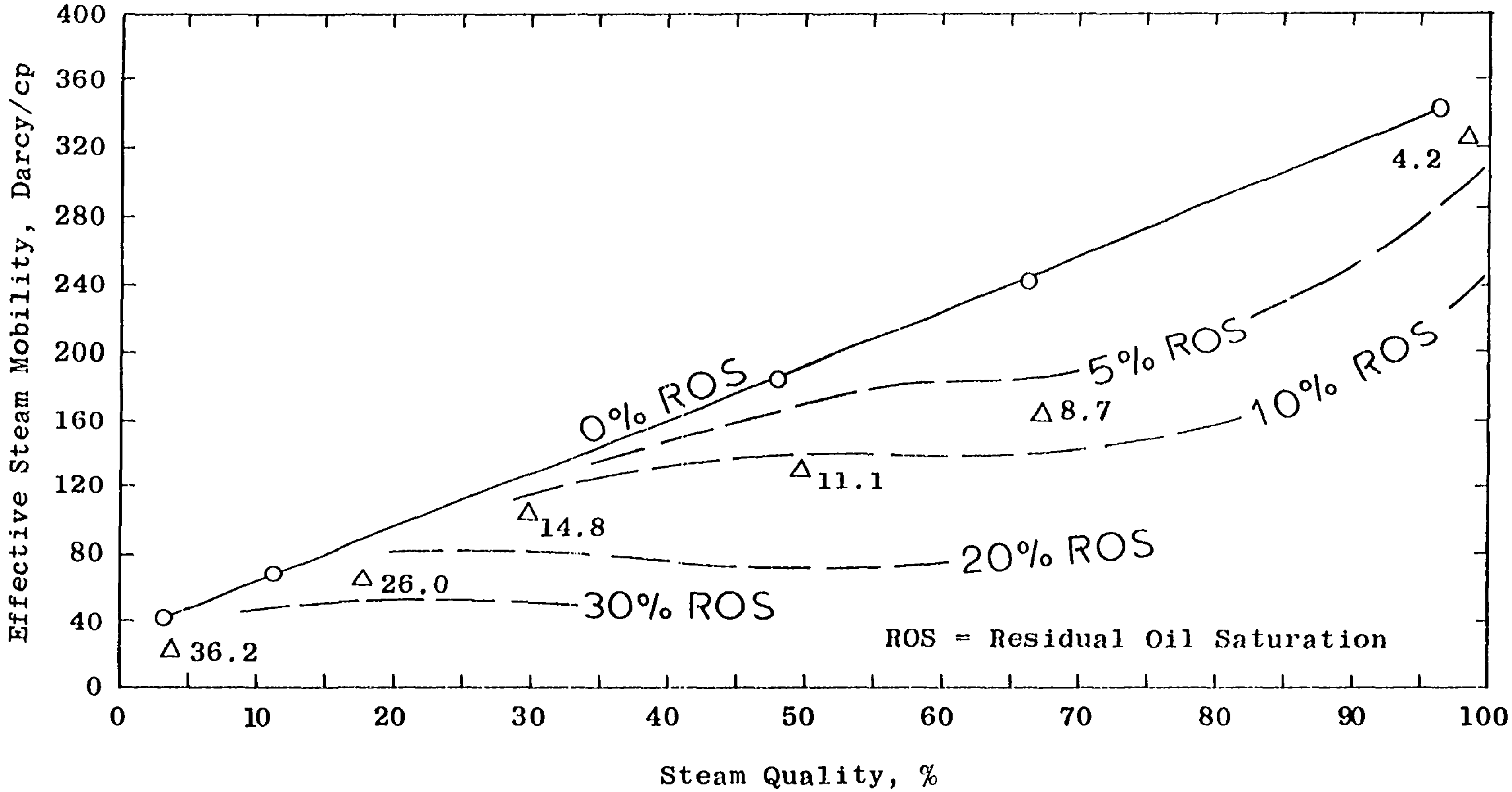

FIGURE 13 EFFECT OF RESIDUAL OIL SATURATION ON THE MOBILITY OF WET STEAM IN BOISE SANDSTONE

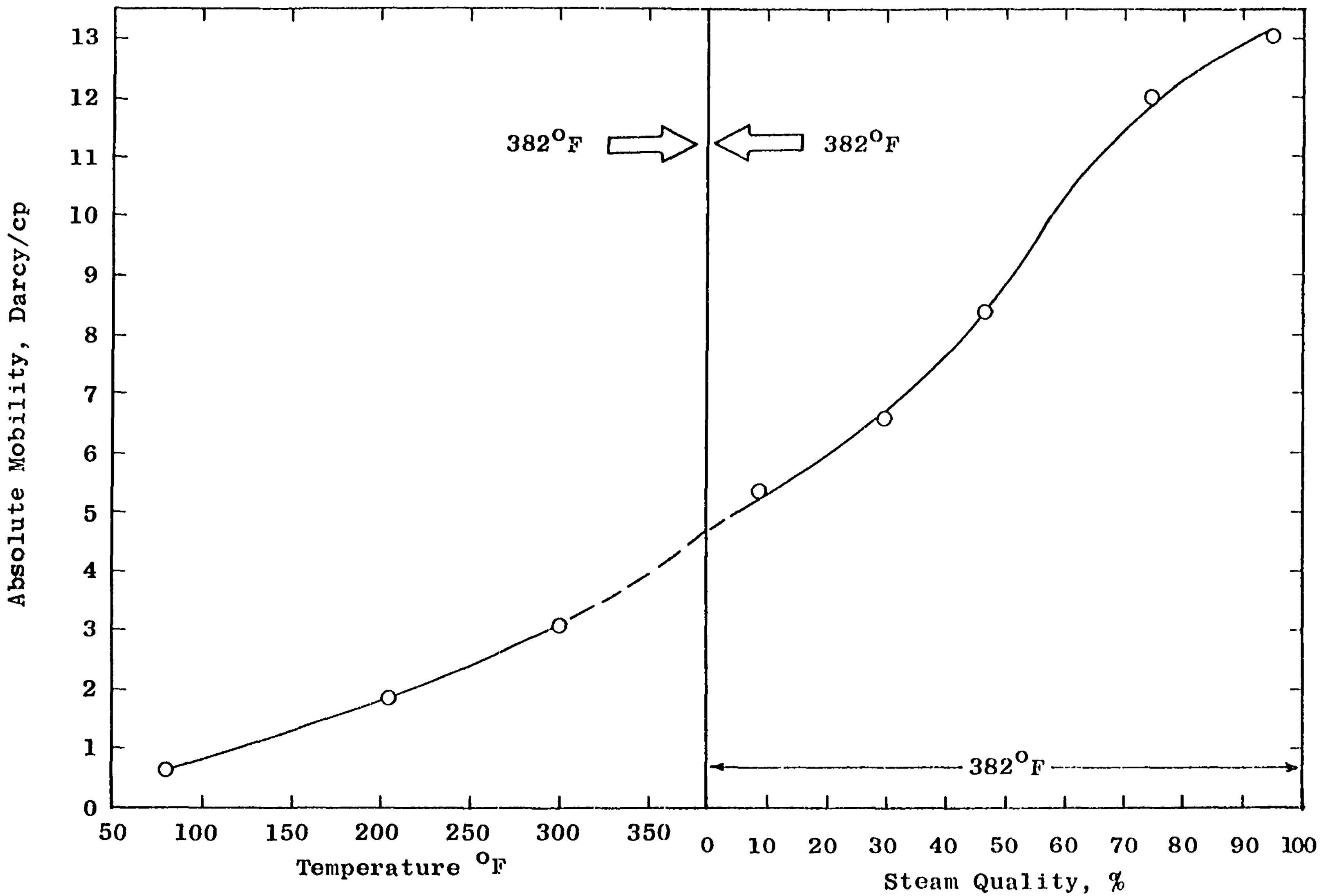

FIGURE 14 COMPARISON OF ABSOLUTE MOBILITIES OF HOT WATER AND WET STEAM IN BEREA SANDSTONE

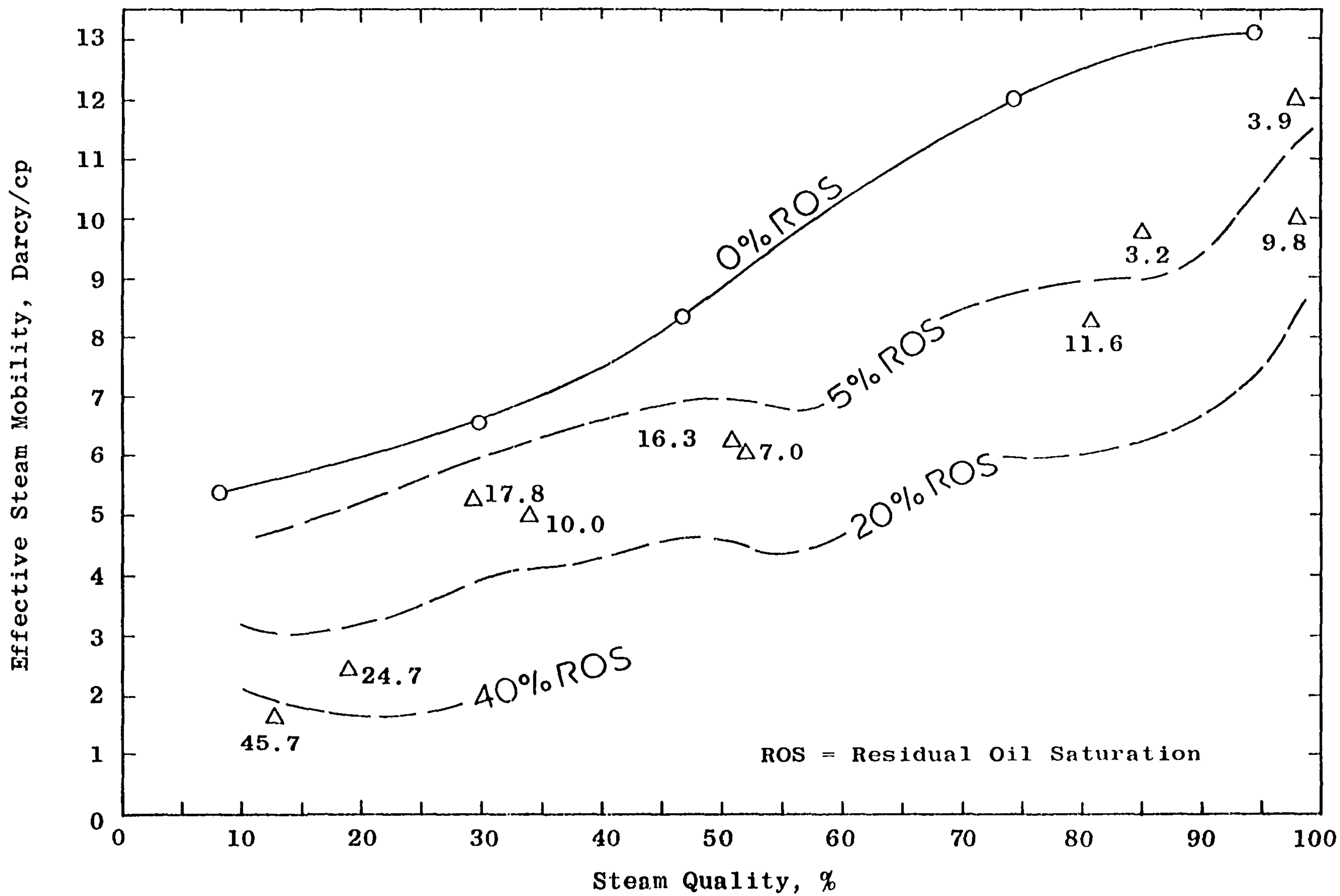

FIGURE 15 EFFECT OF RESIDUAL OIL SATURATION ON THE MOBILITY OF WET STEAM IN BEREA SANDSTONE

The same general type of trend is shown as for the Boise sandstone in Figure 13. In all cases the ROS has an effect on steam mobility but it also appears to decrease with quality. The similarity of the Boise and Berea figures suggested that the ROS may be more dominant in some qualities than others for mobility reduction. Therefore Figure 16 was constructed from the data of Figures 13 and 15 to show the actual percent mobility reduction for each percent residual oil saturation. The result is a curious cyclic type of plot that shows the higher-permeability Boise sandstone to be much more affected by ROS than is the lower-permeability Berea sandstone. An initial reaction is to make a linear correlation through the data with the assumption that the data variation is larger at higher qualities. However there appears to be no basis for assuming a linear relation between mobility reduction and residual oil saturation. The only conclusion that might have merit from this figure is that a general decrease in steam mobility reduction occurs for each percent residual oil saturation present.

A comparison of steam mobilities in the two cores without residual oil saturation shows that although mobilities decline with quality in both rocks, the rate of decline is approximately twice as rapid for the more permeable Boise sandstone. This is not surprising when the exceptionally high mobility of steam in the Boise is

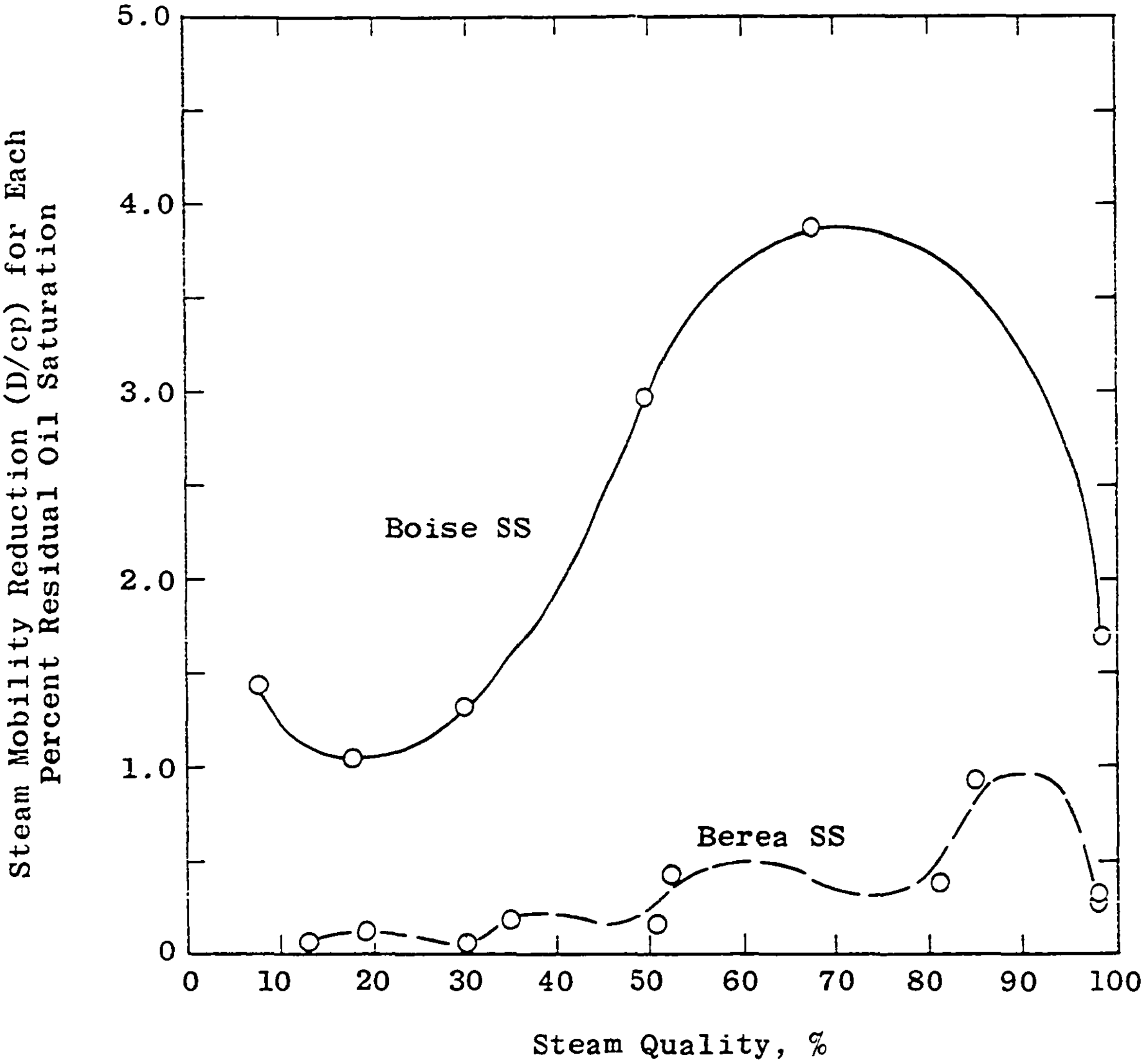

FIGURE 16 EFFECTIVE STEAM MOBILITY REDUCTION PER PERCENT RESIDUAL OIL SATURATION FOR BOISE AND BEREA SANDSTONES

considered. Any liquid holdup from the steam would have a marked effect on mobility. Although this observation is too weak for any significant conclusions, it does suggest heterogeneous rather than homogeneous steam-flow behavior.

Relative Permeability Experiments

In any type of comparative recovery study between two different porous media, relative permeability must be considered. In the present study, a two-phase mixture of steam was used to displace a single phase of oil. Ideally with three phases flowing, three-phase relative permeability data is desired. This type of data is difficult to obtain and only a limited amount of three-phase relative permeability at room temperature has been reported in the literature. No data on three-phase relative permeability with temperature has been reported.

As a basis of comparison in the present study, both hot and cold waterfloods were run on the Boise and Berea sandstones. The purpose of the hot waterfloods was to determine if temperature was a significant factor in relative permeability behavior. Data is presented and discussed for relative permeability ratios and for individual relative permeability curves.

Temperature clearly increased the relative permeability ratio (K_{rw}/K_{ro}) curve for Boise sandstone as shown in Figure 17. At 60% water saturation, the K_{rw}/K_{ro} curve

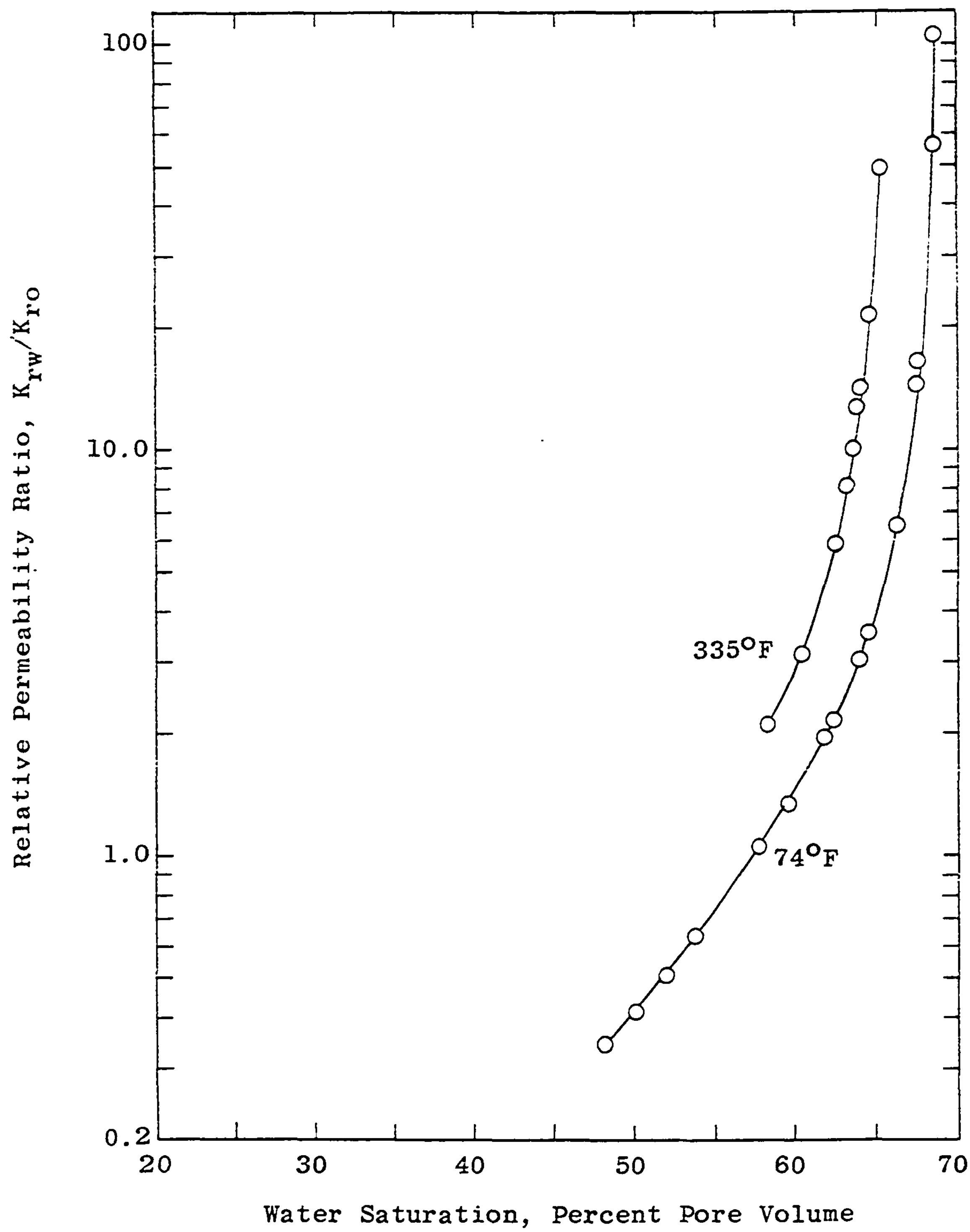

FIGURE 17 EFFECT OF TEMPERATURE ON WATER-OIL RELATIVE PERMEABILITY RATIOS IN BOISE SANDSTONE

increases from 1.5 at room temperature of 74°F to 2.9 at a temperature of 335°F. The general increase appears to be fairly uniform over the saturation values obtained. This means that the Boise sandstone permits greater ease of flow for the water with respect to that of oil with temperature increase. Unfortunately this type of curve doesn't give the effect of temperature on the individual relative-permeability curves. For instance the effective permeability of both curves may decrease or increase with temperature but the ratio will only reflect the relative change.

A technique has been described in the literature[20] where separate relative permeability curves may be obtained from displacement data. An example calculation using this procedure is given in Appendix E. These calculations are simple but rather long and require data in a slightly different form from the conventional Welge[52] relative-permeability ratio plots. A computer program was written to calculate both the individual curves and the ratio. Another computer program using the Welge calculation procedure was also written to calculate the ratio and it was noted that although the results agreed, an increased water saturation span was obtained with the Welge technique.

Results of the study for the Boise sandstone are shown in Figure 18. They indicate that although the relative permeability ratio increases with temperature, both the individual relative-permeability curves for oil and

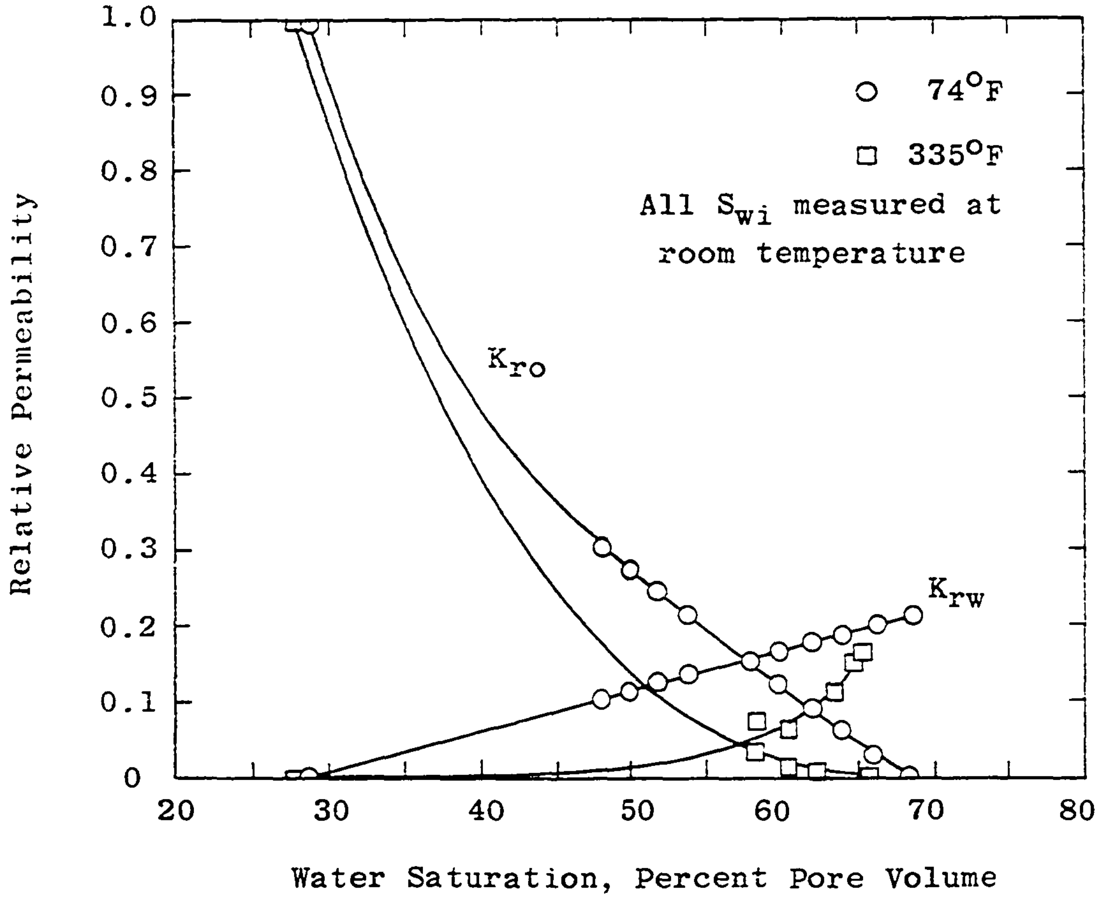

FIGURE 18 EFFECT OF TEMPERATURE ON RELATIVE PERMEABILITY IN BOISE SANDSTONE

water decrease with temperature. Unfortunately, the range of saturation is low because of the high gravity oil used. Ideally the oil should be in the 20-30° API gravity range rather than the 51° API gravity used. A heavier oil could have been used for these floods to give a wider saturation range but as the type of oil can influence rock wettability and hence flow characteristics, it was elected not to change oils.

The production data and corresponding pressure data is shown on Figures 19 and 20. In the cold waterflood the pressure drop was small but recognizable and fairly uniform until near residual oil saturation when the pressures began to fluctuate considerably. In the hot waterflood, although the absolute pressure differential was smaller than the cold waterflood, the change in pressure differential was larger. Pressure fluctuations immediately began with introduction of hot water in the core and remained reasonably uniform until near residual oil saturation when their fluctuations increased.

In contrast to the Boise, the Berea sandstone appeared to be less sensitive to temperature change as shown by the K_{rw}/K_{ro} curve in Figure 21. The figure shows that with temperature the K_{rw}/K_{ro} curve decreases until a water saturation of approximately 49% is reached and then the ratio increases slightly with temperature. Figure 22 shows the individual relative permeability curves and gives a better

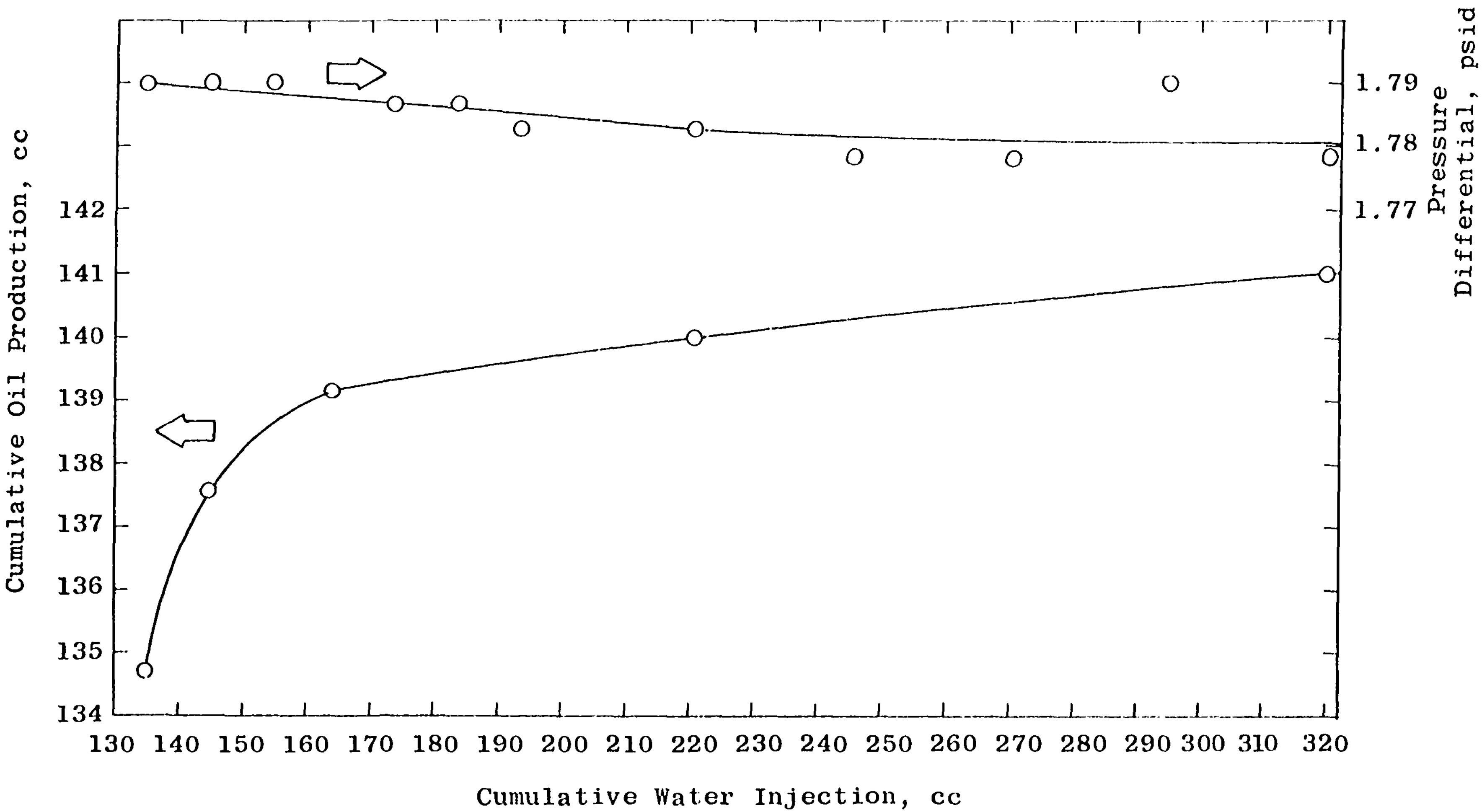

FIGURE 19 CUMULATIVE WATER INJECTED VS CUMULATIVE OIL PRODUCTION AND PRESSURE DIFFERENTIAL FOR COLD WATERFLOOD IN BOISE SANDSTONE

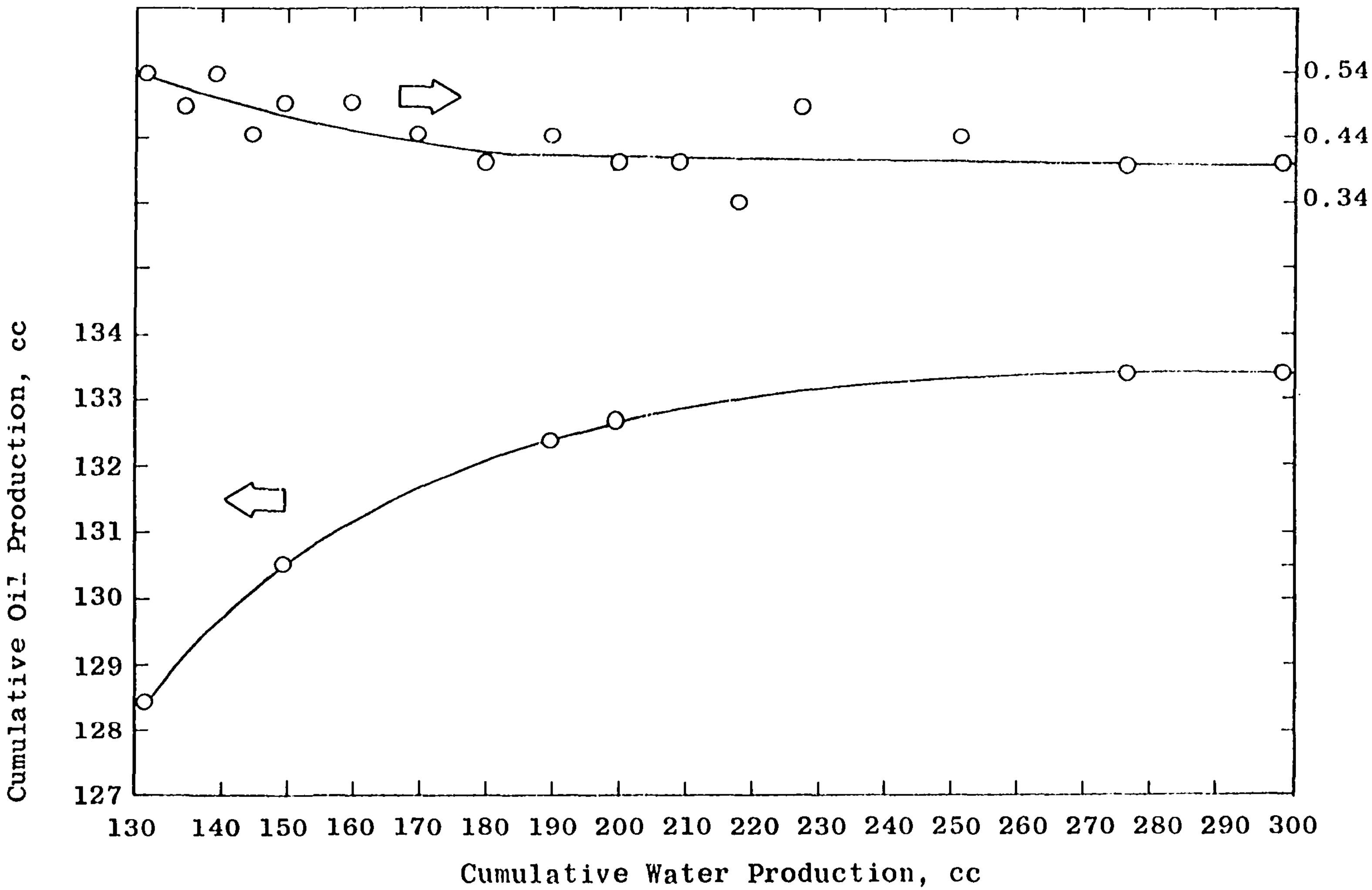

FIGURE 20 CUMULATIVE WATER INJECTED VS CUMULATIVE OIL PRODUCTION AND PRESSURE DIFFERENTIAL FOR HOT WATERFLOOD IN BOISE SANDSTONE

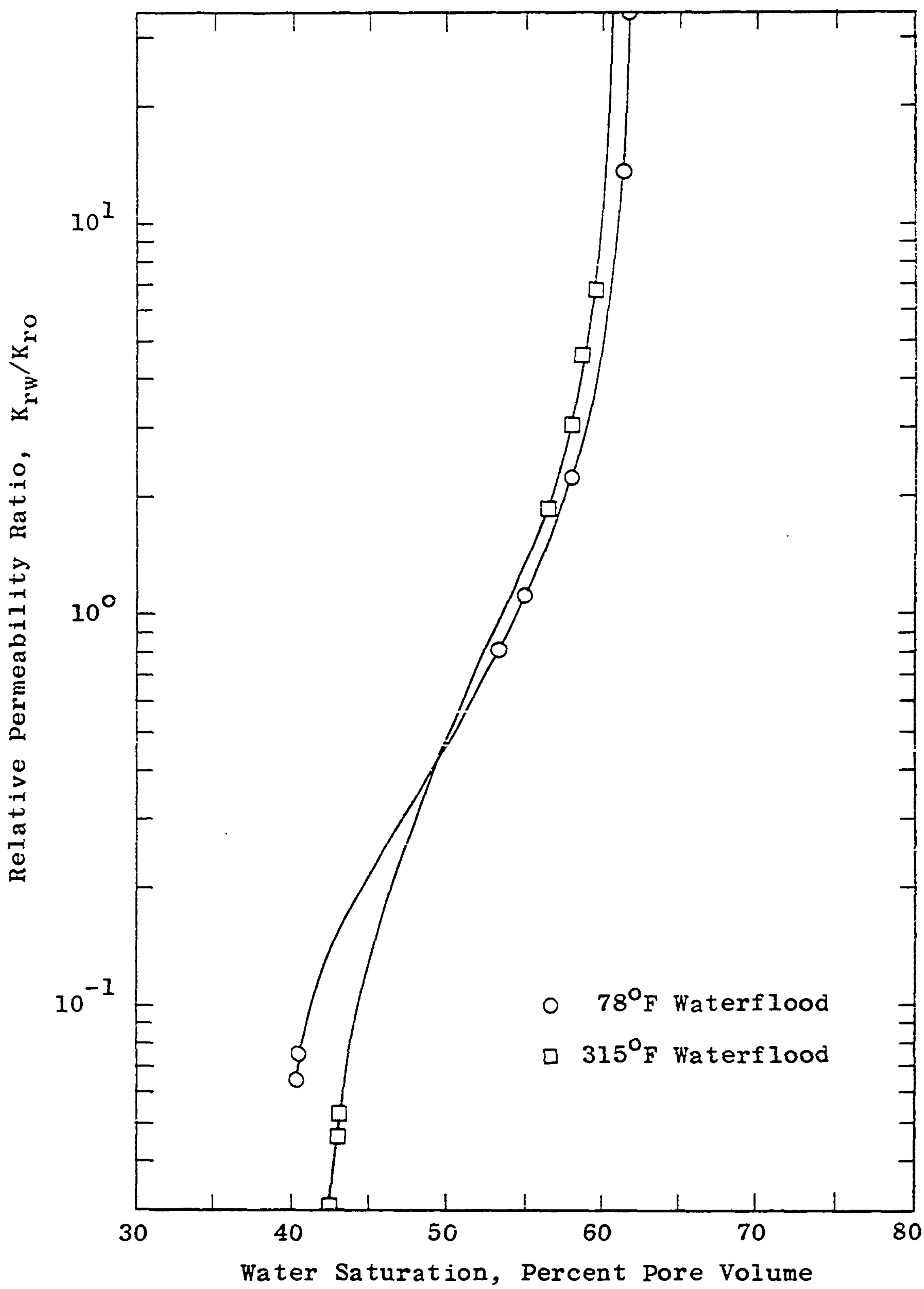

FIGURE 21 RELATIVE PERMEABILITY RATIOS FOR BEREA SANDSTONE

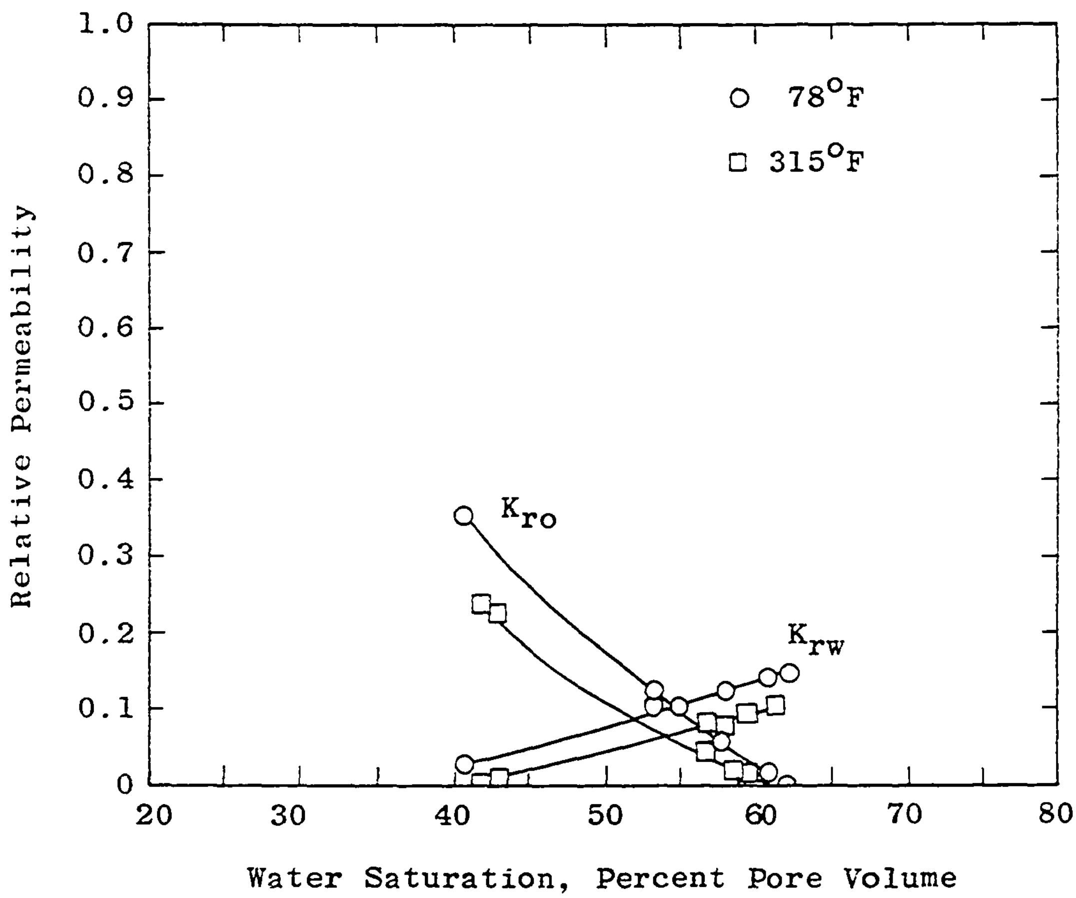

FIGURE 22 EFFECT OF TEMPERATURE ON RELATIVE PERMEABILITY OF OIL AND WATER IN BEREA SANDSTONE

look at temperature effects. As with the Boise sandstone, the relative permeability to both oil and water decreased with temperature, however the decrease appears to be smaller than with the Boise.

As with the Boise, the Berea initial water saturations were determined at room temperature. For the Boise these initial water saturations appeared to be near the irreducible water saturations but for the Berea they were higher and are not shown on Figure 22. An increase in irreducible water saturation with temperature has been reported in the literature.[30,38] The high-gravity oil used and equipment design did not permit an accurate investigation of any suggested increase in irreducible water saturation with temperature in this study.

The production histories and corresponding pressure differential are shown in Figures 23 and 24. Again it should be recalled that these pressure differentials are measured by pressure taps in a 12-inch center section of the core instead of over the full 22-inch core. As with the Boise, the Berea core showed fairly uniform but low pressure-differential drop during the flood, and also as with the Boise the pressure fluctuations were much greater in the hot waterflood.

A comparison of the relative permeability curves is shown in Figure 25 for the room-temperature floods. The Boise shows a higher relative permeability to both oil and

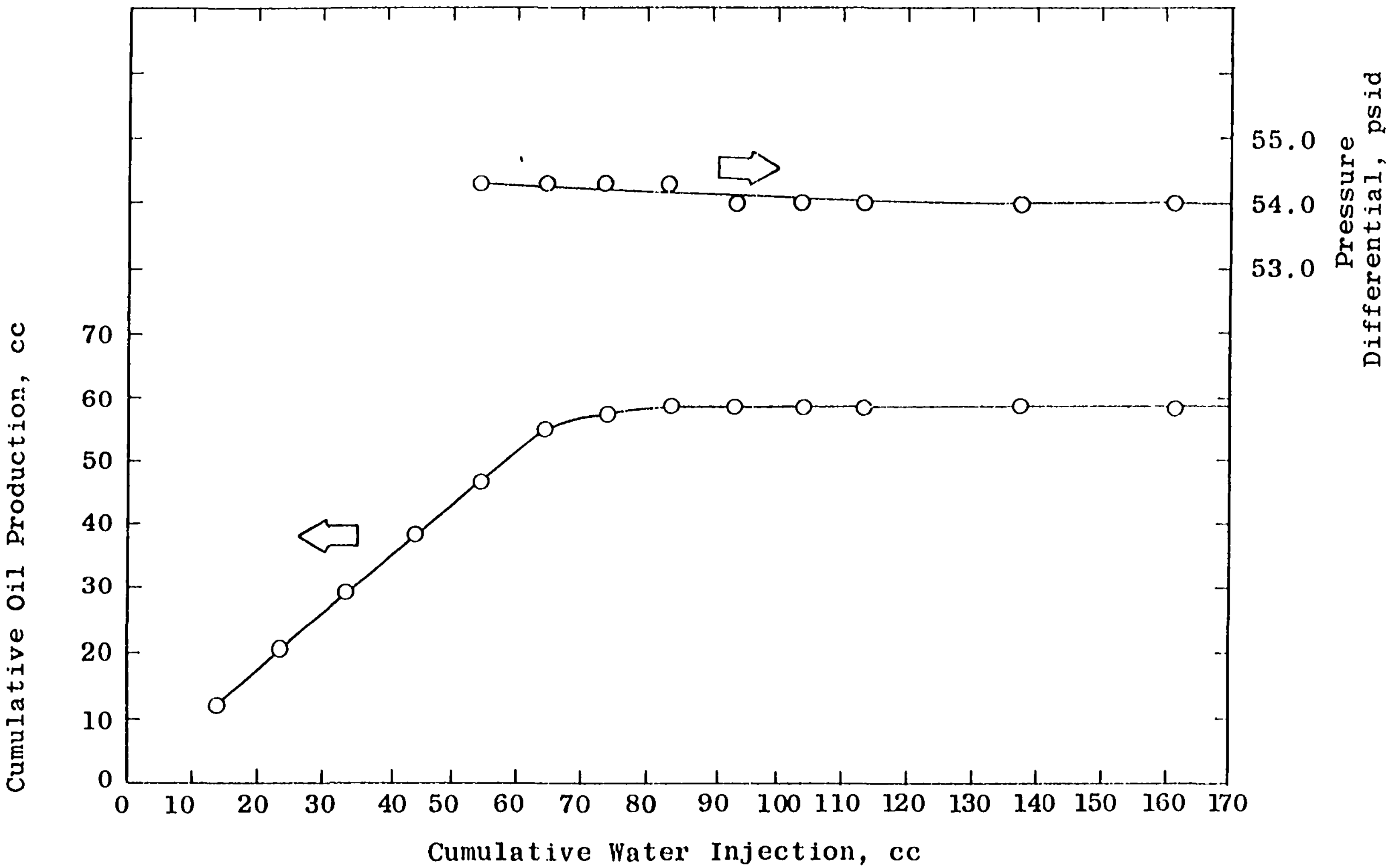

FIGURE 23 CUMULATIVE WATER INJECTED VS CUMULATIVE OIL PRODUCTION AND PRESSURE DIFFERENTIAL FOR COLD WATERFLOOD IN BEREA SANDSTONE

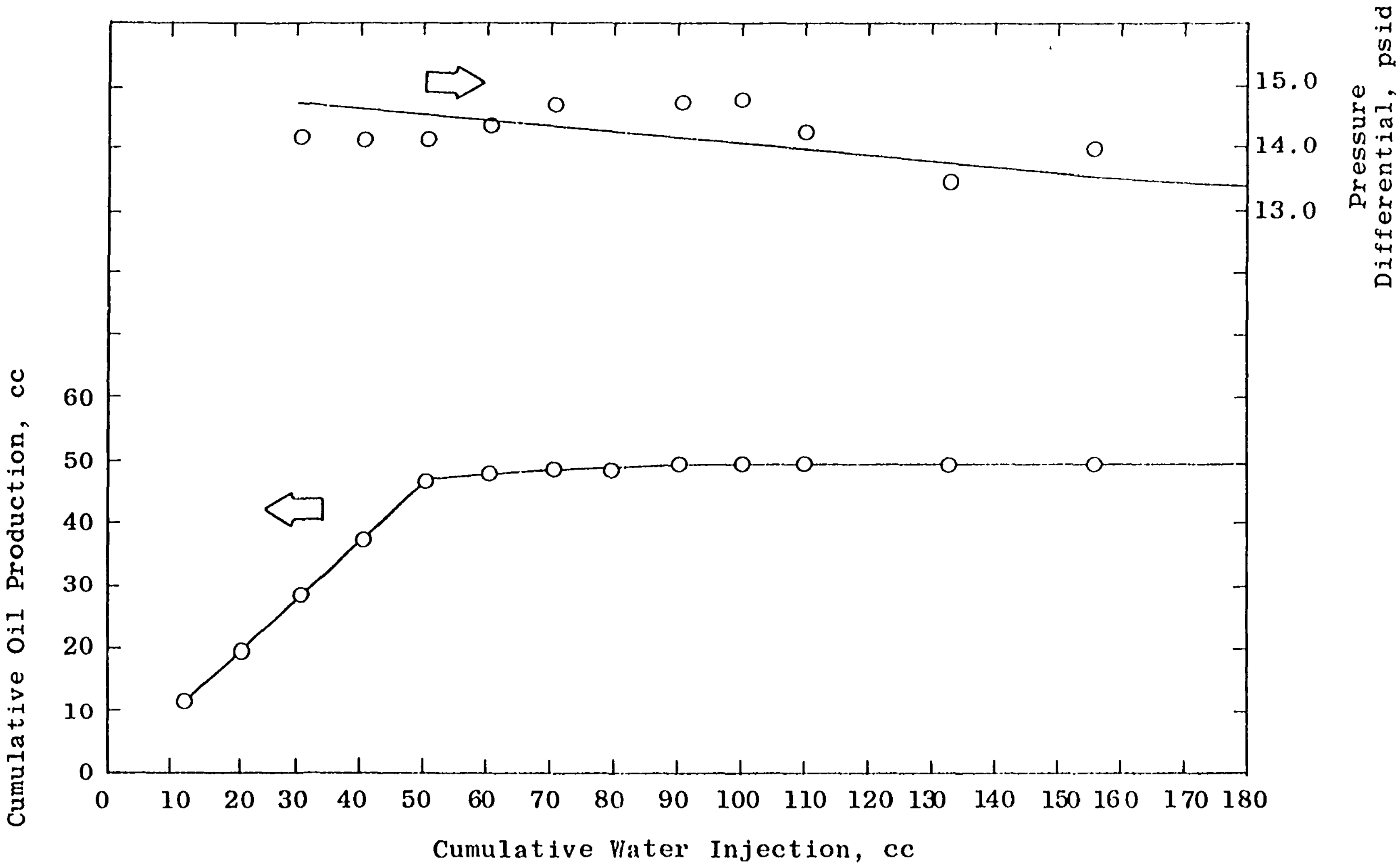

FIGURE 24 CUMULATIVE WATER INJECTED VS CUMULATIVE OIL PRODUCTION AND PRESSURE DIFFERENTIAL FOR HOT WATERFLOOD IN BEREA SANDSTONE

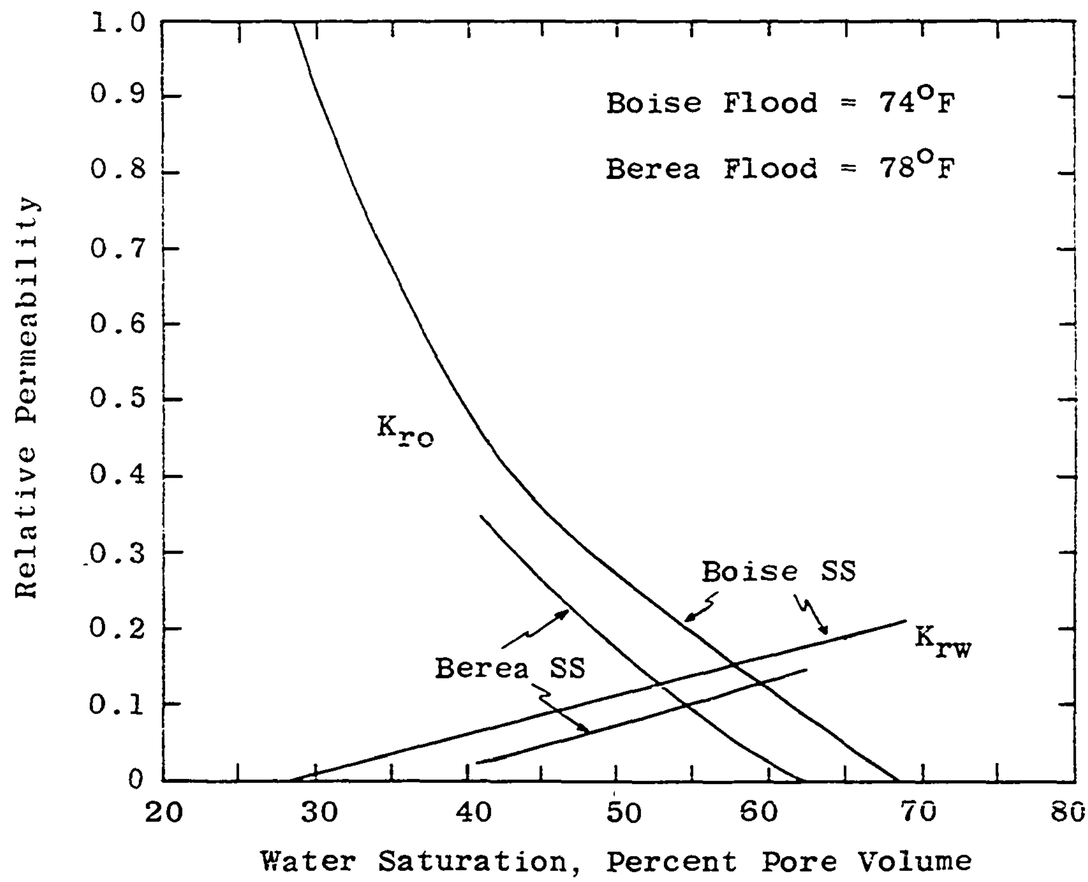

FIGURE 25 COMPARISON OF RELATIVE PERMEABILITY CURVES FOR BOISE AND BEREA SANDSTONES

water than the Berea, although the curves are surprisingly close together. This would indicate that we might expect a greater oil recovery from the Boise than from the Berea core. This is what happened for the waterfloods. As both cores showed a decrease in both K_{rw} and K_{ro} with temperature, it might be anticipated that oil recovery was less for both cores with temperature. Again this is what happened for the waterfloods.

The only results reported in the literature on the effect of temperature on individual K_{ro} and K_{rw} curves is that by Poston et al[30] and Sinnokrot et al.[38] Both of these papers were summarized in the literature-review chapter. Poston and co-workers used displacement data, as in this study, to calculate individual curves by the method of Johnson, Bossler and Naumann.[20] They found that both the K_{ro} and K_{rw} curves increased with temperature which is the exact opposite of the results in this study. Sinnokrot et al calculated separate curves from capillary pressure data using an empirical relation that may not be responsive to temperature. With this procedure, they found that the K_{ro} curve increased with temperature while the K_{rw} curve decreased.

Poston and co-workers used an unconsolidated sand in their study while Sinnokrot and co-workers used a consolidated sandstone. Therefore the present investigation has the first reported results on the effect of temperature on relative-permeability curves in consolidated sandstones where displacement data is used. The results in the present investigation are the opposite of Poston and co-workers but are compatible with the production data. For both the Boise Berea waterfloods, oil recovery decreased with temperature in this study, whereas the oil recovery increased with temperature in the Poston et al study.

Two conclusions of importance to the steamflood experiments are: (1) that fluid flow through both of the cores becomes unfavorable with temperature increase, and (2) the relative permeability curves for the two cores are roughly similar.

Oil Recovery Experiments

The experimental results presented in this section were the primary objective of this investigation. The recovery results for the Boise core are presented and discussed before those of the Berea core. Then a comparison is made between the recovery results of the two cores. In this comparative analysis the effect of pore size on oil recovery as an indirect function of the basic steam displacement mechanism is discussed.

The results of the Boise steamfloods are shown in Figure 26 for adiabatic and non-adiabatic core conditions. Curve B was obtained by isothermal injection of 382^{o}F quality steam into the room-temperature core containing oil and

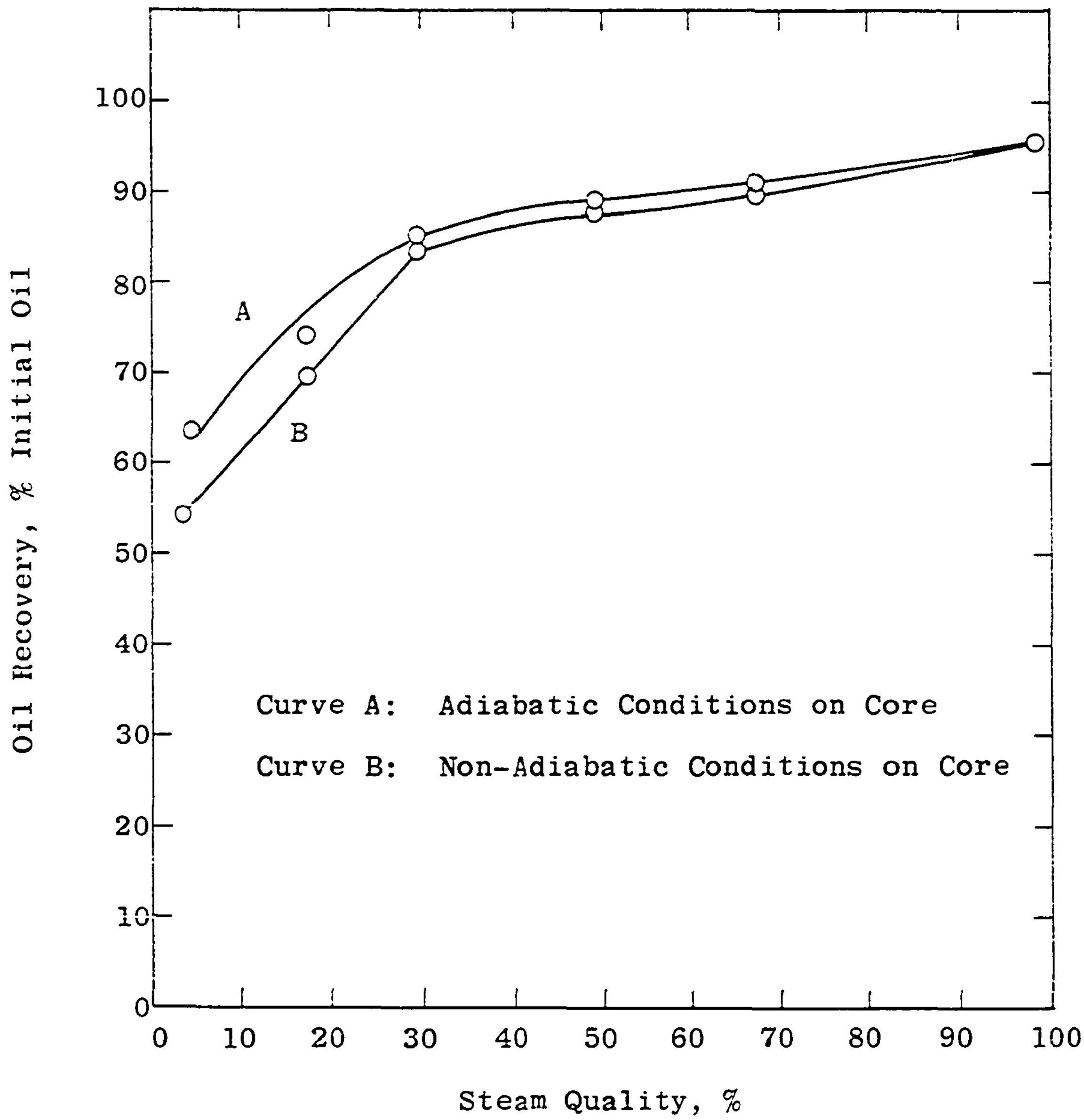

FIGURE 26 OIL RECOVERY VS STEAM QUALTIY FOR ADIABATIC & NON-ADIABATIC CONDITIONS ON BOISE CORE

an initial water saturation. The designated quality steam was injected into the core until steady-state conditions were obtained. External heat loss was permitted from the core at a rate of 0.0280 Btu/min-cm^2. This value was determined experimentally as shown in Appendix F. The recovery curve shows that oil recovery decreased with steam quality at a fairly constant rate until about 30% steam quality and then approximately doubled in decline rate. The type of data shown by Curve B is very qualitative because as the curve shows it is a function of quality. Therefore the recovery curve can be changed as desired by varying the heat-loss parameter of the core's surroundings to some new value for the floods under study. Increasing heat loss will lower the steam quality and although the injection quality is retained the average steam quality of the flood is reduced.

When a given flood on Curve B had reached steady-state conditions, the annulus heat tape was turned on and adiabatic conditions were established on the core by matching the annulus-inlet and-outlet temperatures to the core-inlet and-outlet temperatures. Figure 3 shows that for a small pressure drop, such as occurred in the highly permeable Boise, the quality will remain fairly constant throughout the core. As expected the recovery under these conditions was greater and is shown as Curve A. This increased recovery was most noticeable at the lower qualities ($< 30\%$).

Curve A approaches quantitative interpretation for the particular oil and rock. It permits a look at the actual displacement efficiency of wet steam under steady-state conditions without the complication of oil distillation and viscosity reduction.

Figure 27 shows a comparison of waterfloods and steamfloods in the Boise core. The figure clearly shows that steam is an efficient displacing fluid and that it does not need the mechanisms of viscosity reduction and steam distillation to increase recovery over a waterflood as the Willman et al[53] experiments concluded. Apparently viscosity reduction by steam in the steam displacement process is only a function of temperature and time. If the viscosity is instantaneously reduced to the value dictated by the steam temperature, then Figure 27 shows that the additional recovery is a function of the steam quality. (Recovery would also be a function of rock type and oil composition but this is not shown on Figure 27.) The three curves of Figure 27 appear to meet between an extrapolated oil recovery of 50-54% at 382°F with no apparent mobility discontinuity between the waterfloods and the steamfloods. Note that oil recovery decreased for the hot waterflood as compared to the cold waterflood. This is in agreement with the relative permeability data.

Repeatability of the oil recovery data was good and as previously shown in the literature,[13,53] the final re-

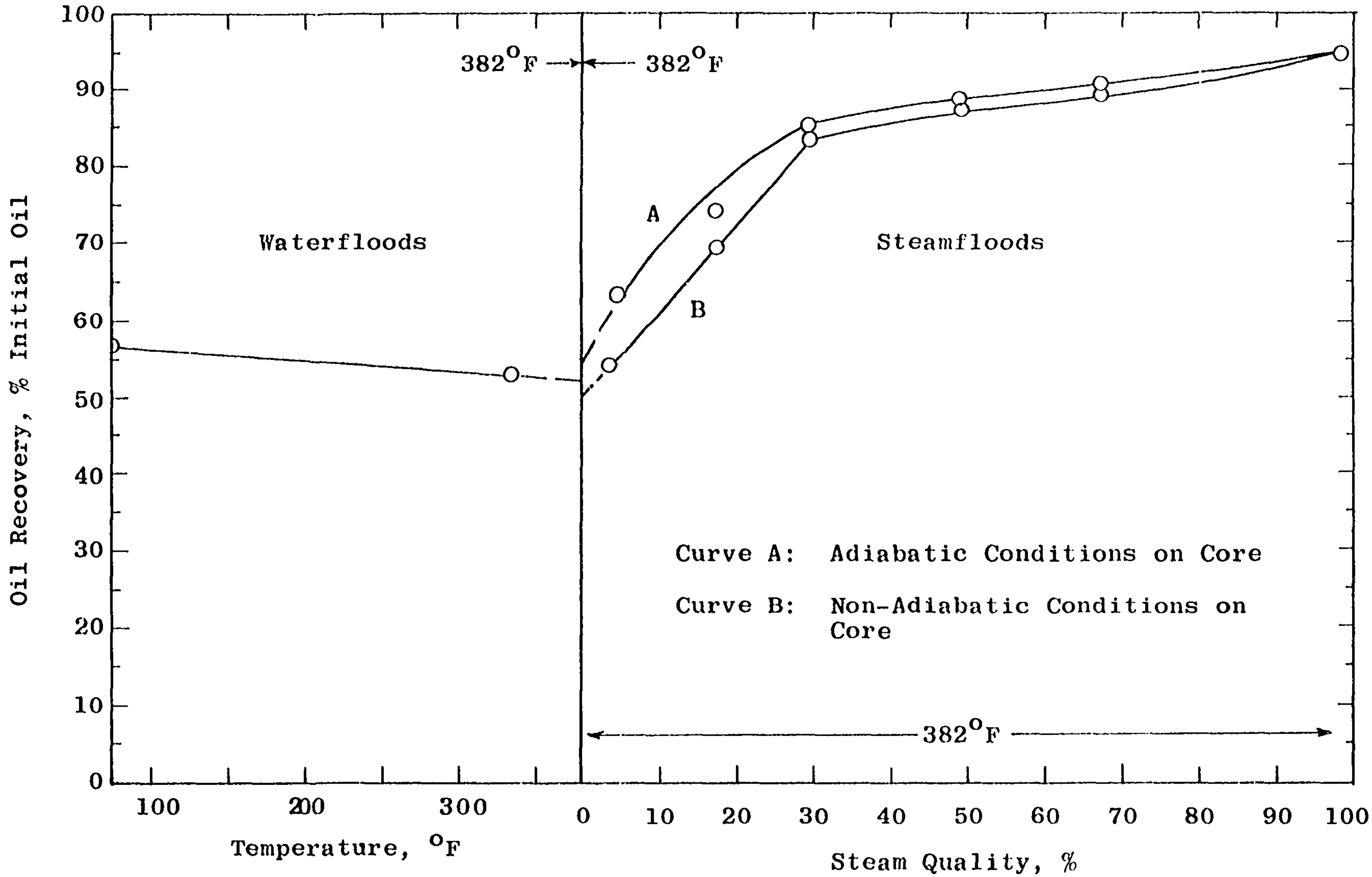

FIGURE 27 COMPARISON OF WATERFLOODS AND STEAMFLOODS IN BOISE SANDSTONE

covery was found to be independent of the initial recovery process. This is demonstrated in Figure 28 which is the production history of a cold waterflood followed by a steamflood. The waterflood recovered 55.2% oil before start of the steamflood. This recovery compares with a recovery of 56.4% for a second cold-waterflood run at a later time. (In this second waterflood the injection rate was cut in half to verify rate independence of the waterfloods.) High quality steam (97.3%) was introduced into the core following the first cold waterflood and recovered 94.8% of the initial oil at steady-state conditions. A separate steam run without the waterflood at a steam quality of 98.3% recovered 95.2% of the initial oil.

The production history of the waterfloods and steamfloods in the Boise core is shown in Figures 29 and 30. Water breakthrough occurred on all floods between 47 and 54% oil recovery while steam breakthrough varied from about 65% on the lowest quality run of 17.8% where steam breakthrough could be definitely noted to 85% at the highest quality flood. Examination of both the production figures suggest that all but the 17.8% quality flood with the annulus heat tape on approached steady-state conditions. This fact was noted in drawing the data correlation curve of Figure 26 discussed previously.

The efficiency of the waterfloods with high gravity oil is evident by the high oil recovery before water break-

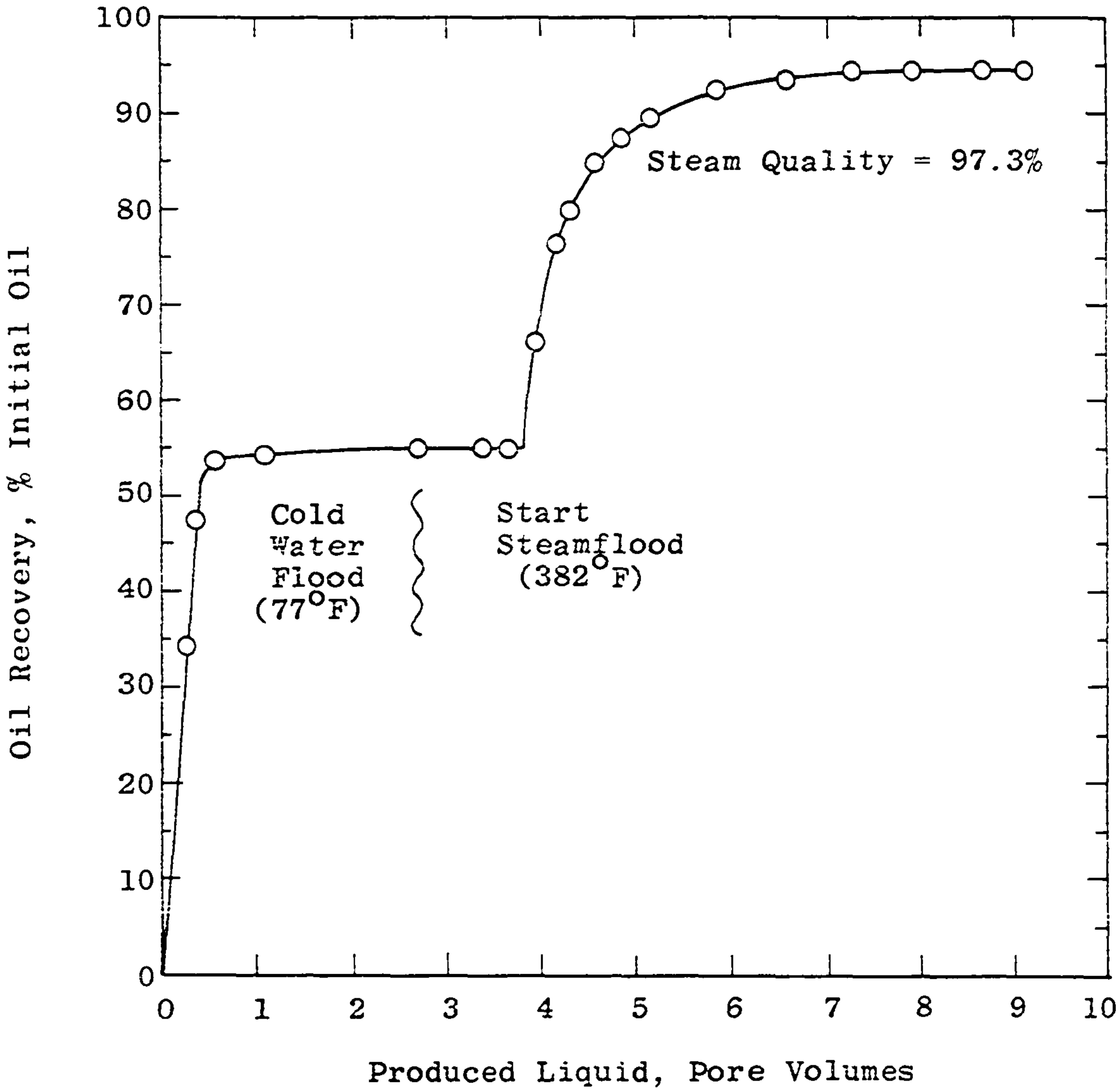

FIGURE 28 PRODUCTION HISTORY OF COLD WATERFLOOD FOLLOWED BY STEAMFLOOD

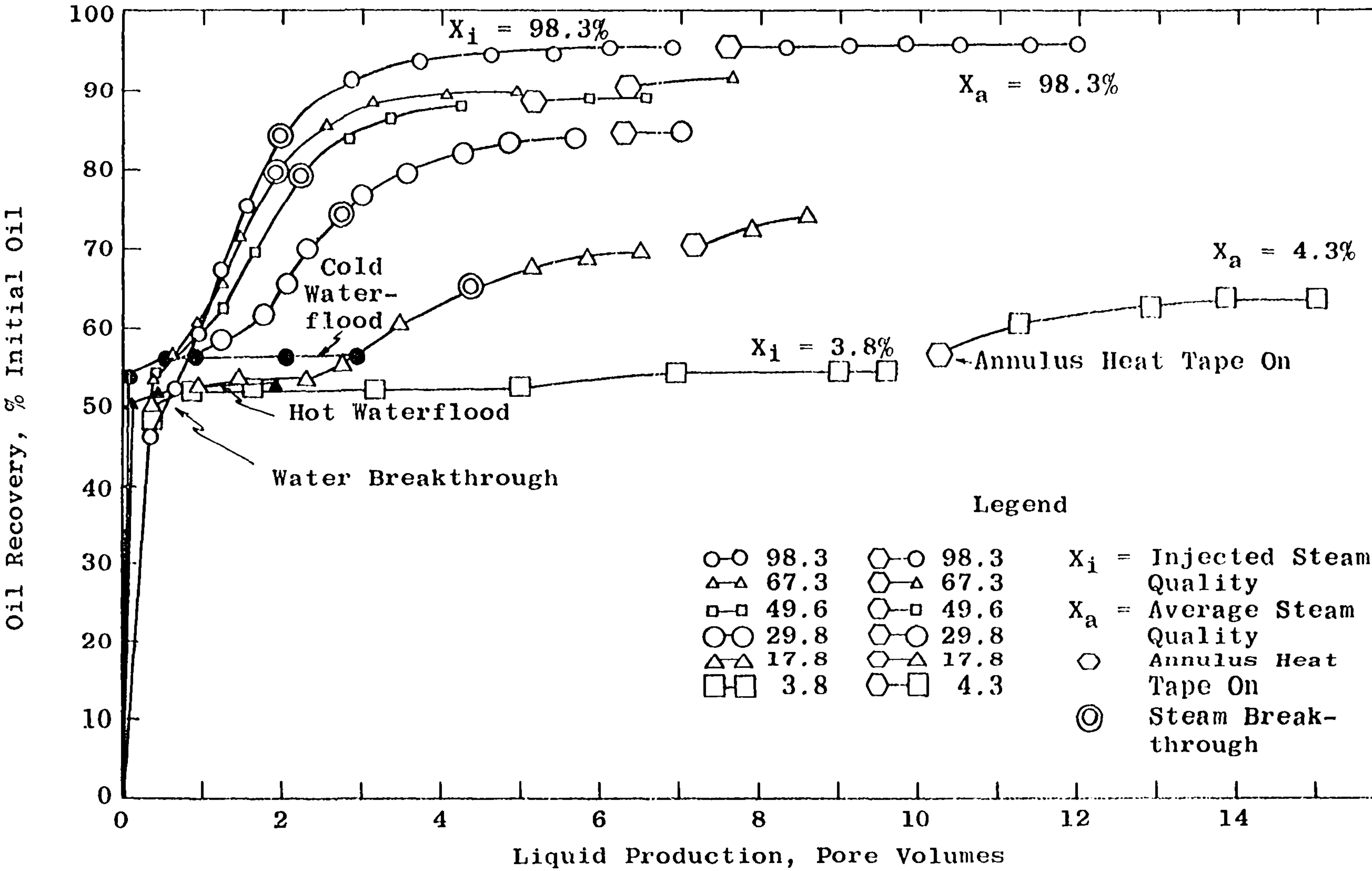

FIGURE 29 LIQUID PRODUCTION VS OIL RECOVERY: BOISE SANDSTONE

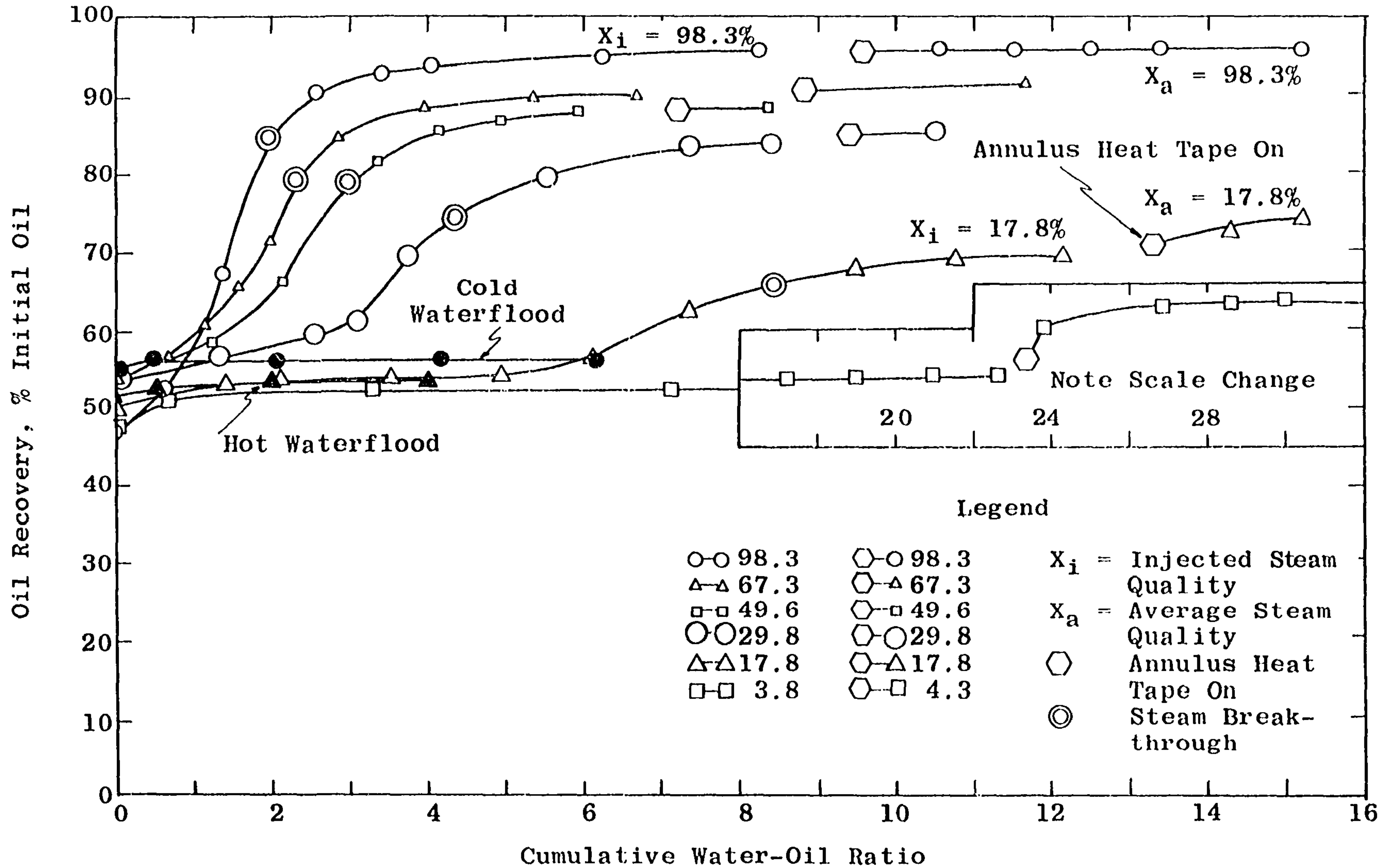

FIGURE 30 CUMULATIVE WATER-OIL RATIO VS OIL RECOVERY: BOISE SANDSTONE

through. After water breakthrough only a small amount of additional oil was recovered on both the hot and cold waterfloods. Figure 29 also shows that for 0.5 pore volume of injected fluid, the cold waterflood had a higher percent recovery than any of the steamfloods. The quality of production data in the Boise core was good and a correlation between water breakthrough and steam breakthrough as a function of quality was obtained. This correlation and a correlation of the same factors for the Berea core are presented after the following discussion on the oil recovery results from the Berea.

The oil recovery results for the Berea core are shown in Figure 31 as two curves which reflect a difference in pore volumes of production. Initially it was intended that the upper curve simply provide more control points on the first curve. However, the results show that even with an average of 7 pore volumes of production, more recoverable oil (than was anticipated by observing the effluent) was available before the annulus heat-loss conditions were modified. The problem of reaching an end point is always present in low permeability cores, and therefore a practical instantaneous water-oil ratio is usually picked as a cut-off point. In the present case a WOR of 250 was used as a guide before turning the heat tape on. The net result is the same as production without the heat tape on because the same upper curve would have been obtained in either event.

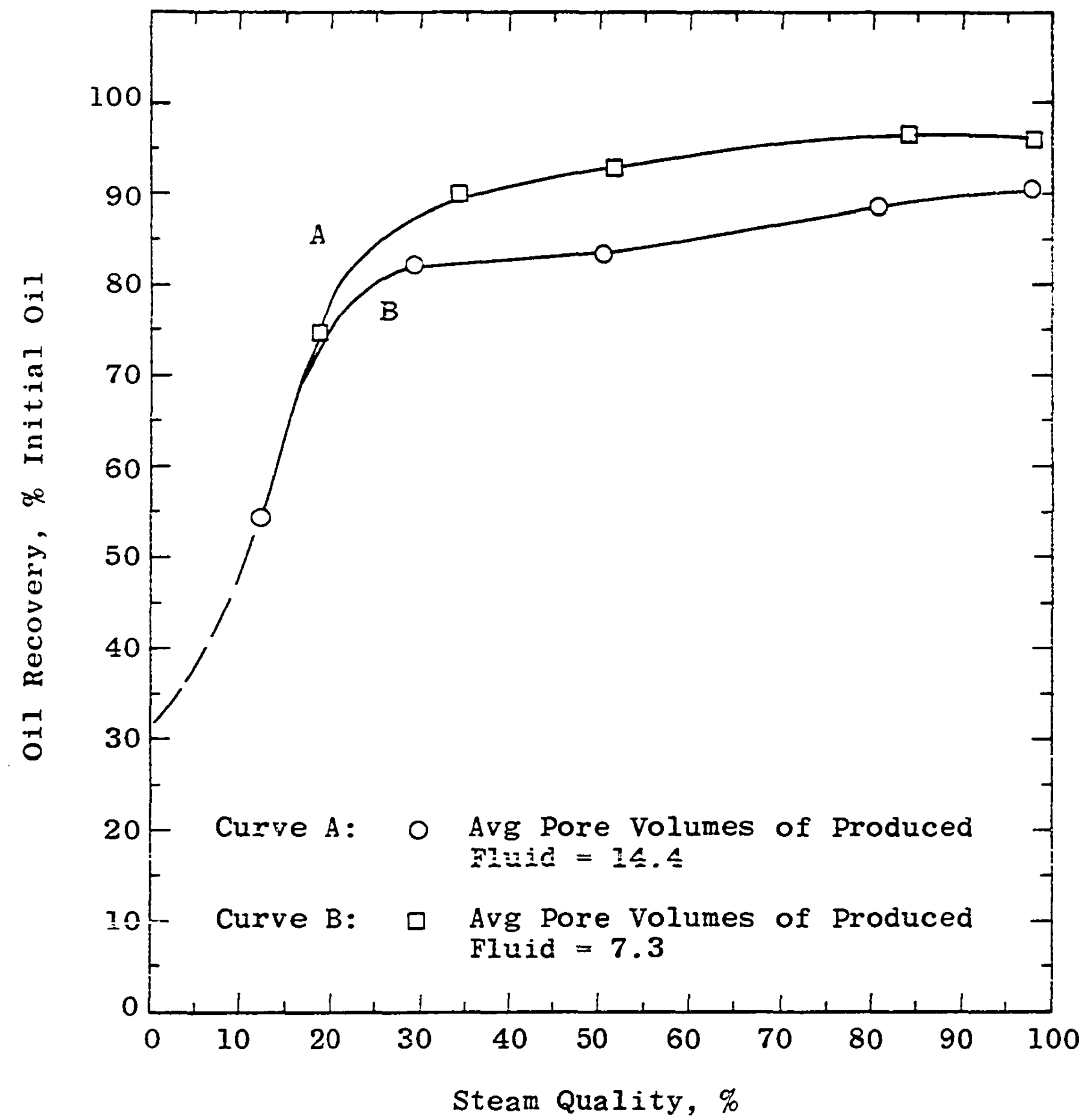

FIGURE 31 OIL RECOVERY VS STEAM QUALITY FOR BEREA SANDSTONE

The results are presented in this manner because a variable in the experiments was changed.

A comparison between the waterfloods and steamfloods is shown in Figure 32. The waterflood results are similar to those for the Boise in that recovery decreased with the hot waterflood. Extrapolation of the waterfloods to 382^{o}F and the steamfloods to 0% quality both suggest approximate recoveries of 32%, but a mobility discontinuity is possible for qualities less than about 5%.

The production histories are shown on Figures 33 and 34. As with the Boise core, the waterfloods recovered most of their oil before water breakthrough. More difficulty was encountered however in picking the steam-and water-breakthrough points in the Berea than in the Boise. For the steam breakthrough this difficulty was caused by the continuous core back-pressure adjustment to retain isothermal steam injection at the core face. This back-pressure adjustment caused the temperature on the core outlet to vary in such a manner that the rapid temperature increase, characteristic of steam breakthrough, was difficult to locate accurately.

A possible correlation with quality for water breakthrough and steam breakthrough appears to exist for both the Boise and Berea cores and is shown in Figure 35. The results indicate that steam breakthrough is a function of steam quality and probably of permeability. It is known

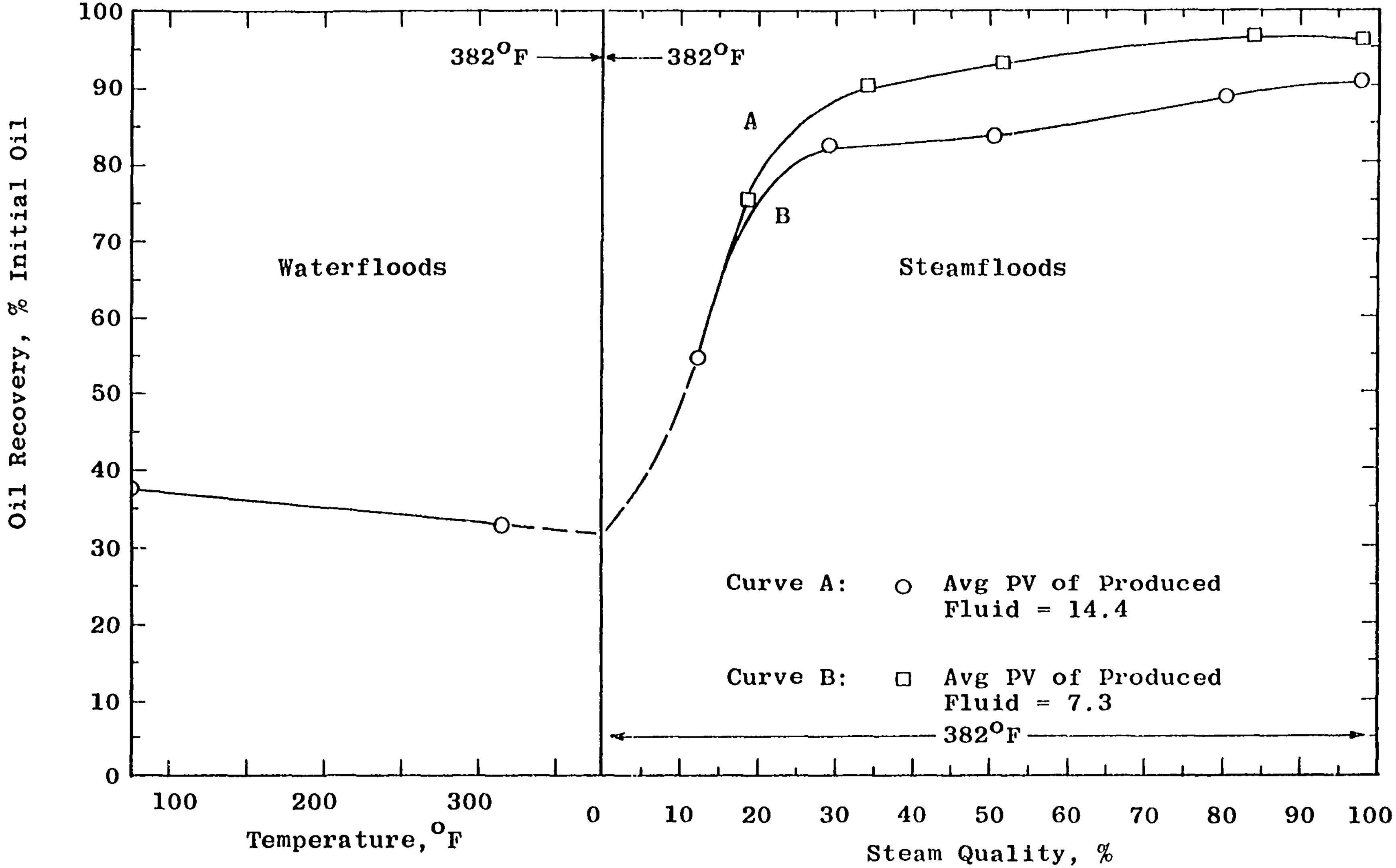

FIGURE 32 COMPARISON OF WATERFLOODS AND STEAMFLOODS IN BEREA SANDSTONE

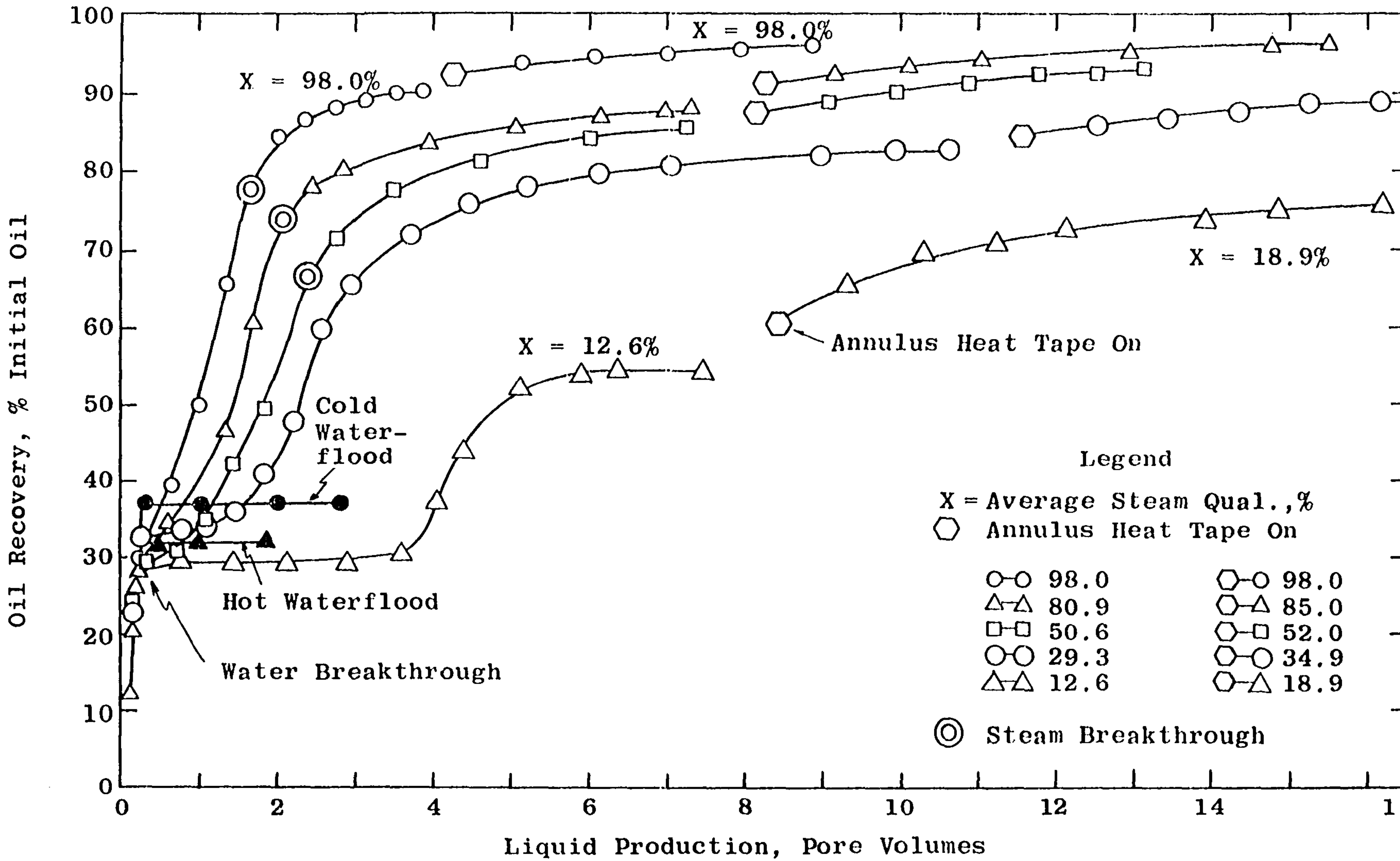

FIGURE 33 LIQUID PRODUCTION VS OIL RECOVERY: BEREA SANDSTONE

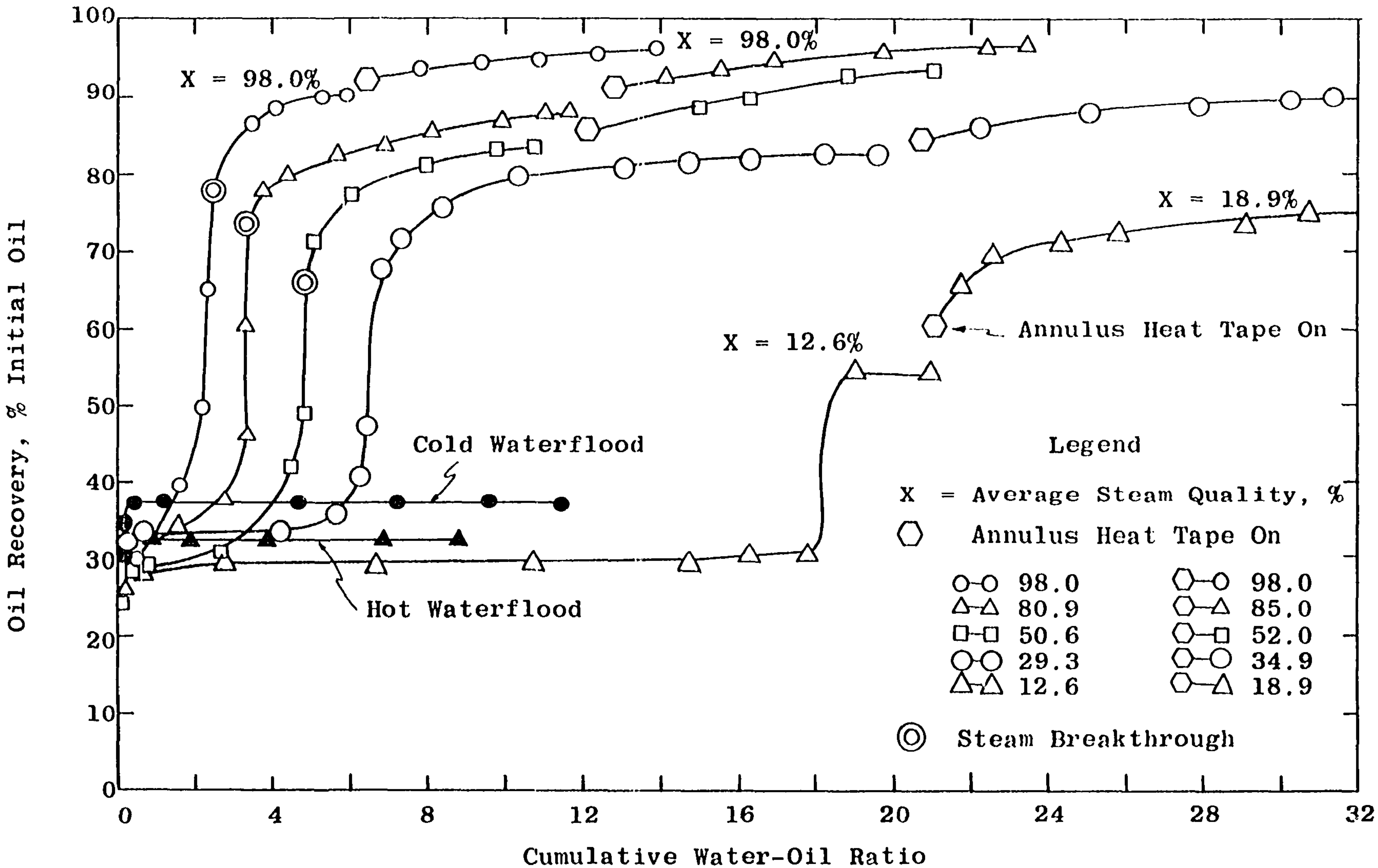

FIGURE 34 CUMULATIVE WATER-OIL RATIO VS OIL RECOVERY: BEREA SANDSTONE

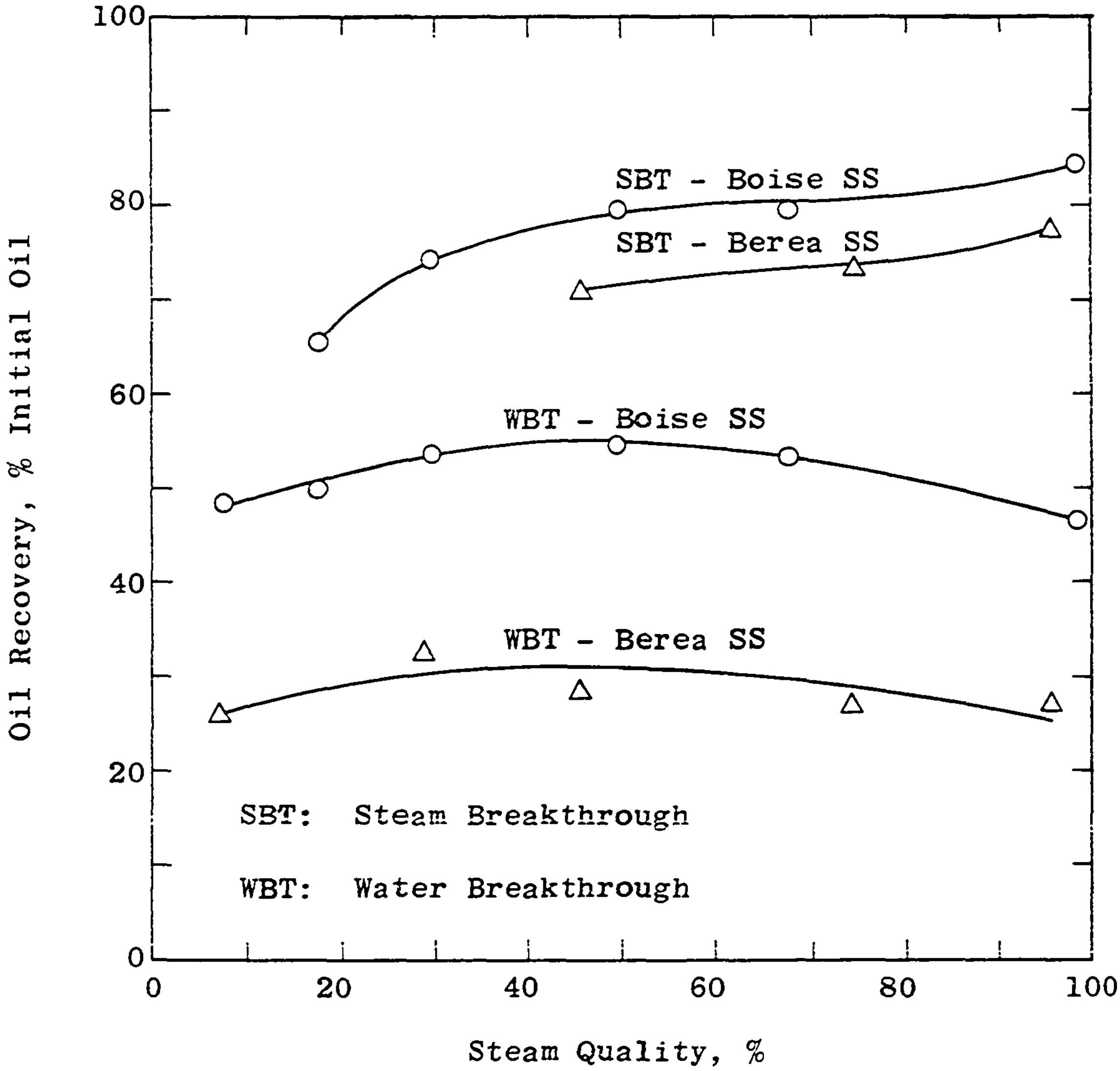

FIGURE 35 STEAM BREAKTHROUGH AND WATER BREAKTHROUGH AS A FUNCTION OF STEAM QUALITY

that the displacing fluid breakthrough is a function of injection rate, and as the average steam injection rates are 15 and 9 cc/min respectively for the Boise and Berea, any comparative conclusions may not be justified. The similarity of the curves however is rather striking. The increase in percent oil recovery before steam breakthrough with steam-quality increase and thus vapor-content increase shows the efficient displacement process of steam is more than a function of vapor mobility. The water breakthrough curves are interesting but why they are convex upward is not understood at this time.

A comparison of the oil recovery results for both cores are shown in Figure 36. The results indicate that on an ultimate, steady-state basis the lower permeability Berea (0.5 darcy) will yield more oil to steamflooding down to a quality of approximately 20% than will the higher permeable (8.1 darcy) Boise. Surprisingly the higher permeability core is more responsive to low quality floods than the lower permeability core. On a microscopic basis, the larger liquid volume of the lower quality steam could afford a greater degree of small pore flooding relative to that of vapor and thus more oil recovery. This is based on relative permeability considerations where liquid flows predominantly in the small pores and vapor in the larger ones.

An observation from Figure 36 is that something has happened to the steam displacement mechanism in both cores

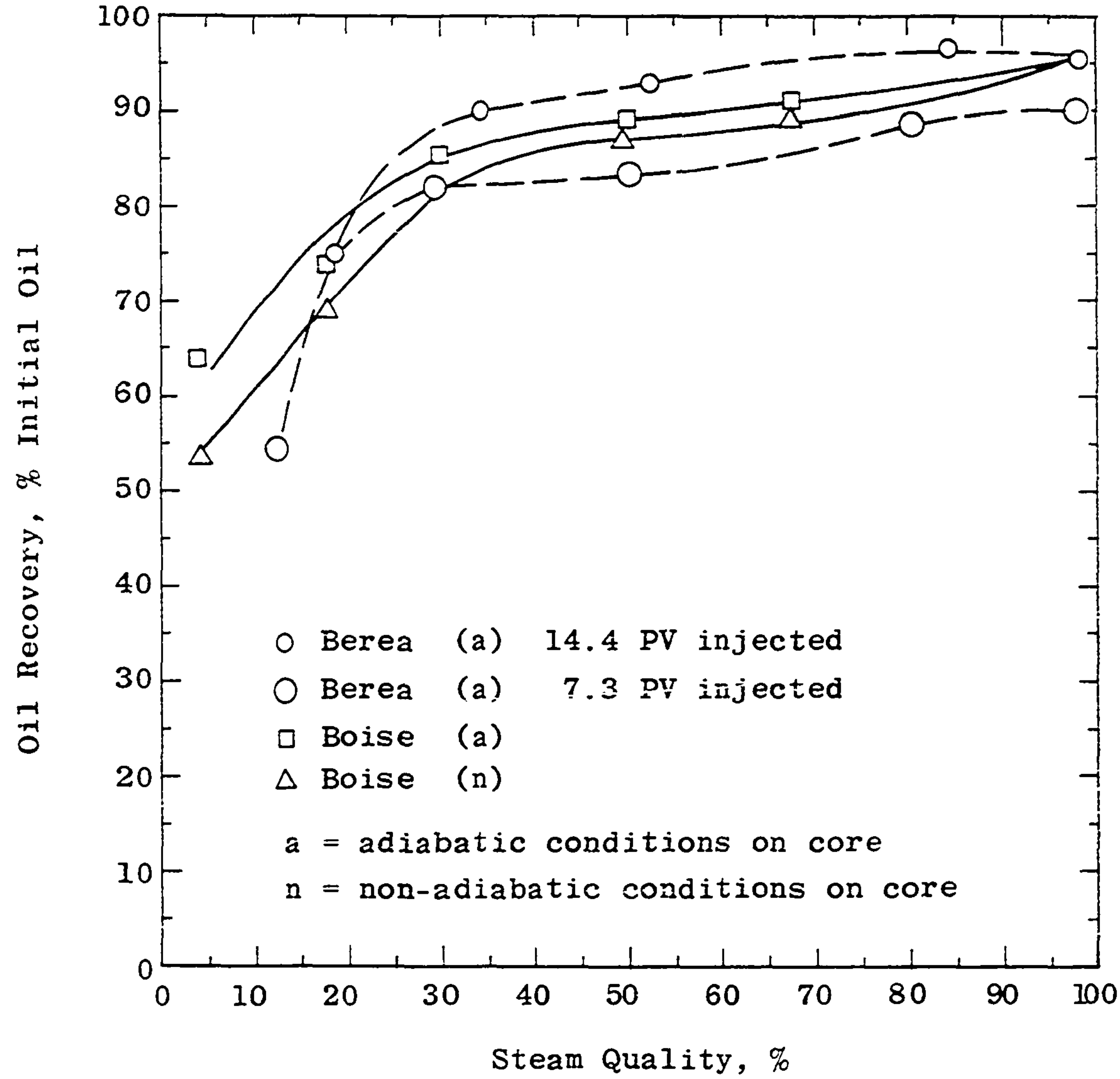

FIGURE 36 COMPARISON OF OIL RECOVERY FOR STEAMFLOODS IN BOISE AND BEREA SANDSTONES

at around 30% steam quality. The 30% quality run on the Berea core was repeated and the new results were within 1%. In a previous study[18] of quality steam with 15.4° API oil and with non-adiabatic conditions on the core, an abrupt break also occurred at about 30% quality. Because of its anomalous nature the run in that study at 34.4% injected quality was repeated. The new results were also within 1% of the old.

Comparison of the Berea and Boise results from Figure 36 suggests that the mechanism is independent of pore size (8.1 darcy vs 0.5 darcy). When these results are compared with the results of Halbert (15.4° API oil),[18] then the mechanism appears to be independent of viscosity (1.2 cp vs 0.33 cp at 382°F). The steam mobility results on both cores might be checked to see if any type of mechanism change is indicated. Figure 13 for the Boise shows the ROS curves starting to bunch at around 30-40% steam quality. However this only means that the steam mobility is becoming less sensitive to the percent ROS as shown by Figure 16. Figure 15 for the Berea doesn't show any anomalous behavior. The relative permeability curves do not appear to be of any assistance. We might try to explain this change in terms of a basic mechanism change. However two things are against this: (1) Steam breakthrough occurred on all runs because of adiabatic conditions on the core and, (2) The steam mobility data does not suggest any hot water-steam mobility discontinuity.

Another interesting feature of Figure 36 is that only 3-4% initial oil recovery separates the adiabatic Boise curve and the adiabatic Berea (14.3 PV) curve down to 20% steam quality. This leads to the conclusion that pore size as suggested by absolute permeability does not significantly affect the total possible oil recovery from a rock by steamflood. However pore size does affect pressure drop and as will be discussed shortly, the suggested mechanism that relates oil recovery and steam quality is pressure dependent.

The steam mobility curves discussed earlier decreased with quality decrease. Thus they suggested that from strictly a mobility aspect, a more favorable mobility ratio existed at increasingly lower qualities. Therefore as the mobility of the displacing phase decreased the displacement efficiency increases and more recovery should result. This is in conflict with experimental results, so some additional or over-riding mechanism must be present.

To examine the oil recovery for a given unit of rock at some point in time before steam breakthrough requires an unsteady-state analysis for the different parts of the rock or reservoir swept by the displacing phase. Calculations based on respective areas swept by the cold waterflood, hot waterflood and steam zone of the steam displacement process must be made. In such an analysis, the point where convective heat losses through the steam front become sufficiently large to cause a change in basis displacement from one of steam-liquid to liquid-liquid becomes important. The theoretical basis for such an analysis has been discussed by previous investigators.[18,24]

To examine the oil recovery from steady-state experiments after steam breakthrough requires only an examination of the efficiency of the steam displacement process. Efficiency in general (as used here) includes all the available displacement mechanisms related to the steam displacement process which will move oil out of the rock. These were discussed earlier and include such effects as distillation, viscosity reduction and fluid expansion. With distillation removed and viscosity reduction and fluid expansion minimized, then the steam displacement process reduces to the more elementary problem of examining the basic physical displacement mechanism of steam.

The importance of the steam mobility experiments can now be seen. On a mobility ratio basis they do not explain the decline in the percent oil recovery with steam quality decrease but this needed to be definitely established.

It is proposed that the basic steam displacement mechanism is the ratio of the specific volume of steam at its displacement pressure to the specific volume of the produced liquid. With this postulate the oil recovery results in this investigation can be explained. Instead of an instantaneous value of specific volume with displacement pressure, an average core pressure is used to obtain an average specific volume.

A plot of specific volume at the arithmetic average pressure in the core for each steamflood against the corresponding average steam quality is shown in Figure 37. A good linear correlation exists for the Boise sandstone which is not surprising because of the small pressure drop in the core. A linear correlation for the Berea shows more deviation than for the Boise and becomes erratic at higher qualities. This behavior is primarily a measure of pressure variation in the floods. Specific volume when plotted against steam quality at a constant pressure gives a linear relation. Figure 38 shows this relationship. Figure 37 can then be interpreted to mean that for a given length of rock with a high gravity, non-distillable oil, the average pressure can be treated as constant over the spectrum of steam quality runs made. This result would be difficult to anticipate without these experiments because of the changing residual oil saturations for the steamfloods and other variables in the displacement process. The value of such a correlation is that it permits ultimate oil recovery to be examined on the basis of specific volume of the displacing steam.

The relationship between oil recovery and specific

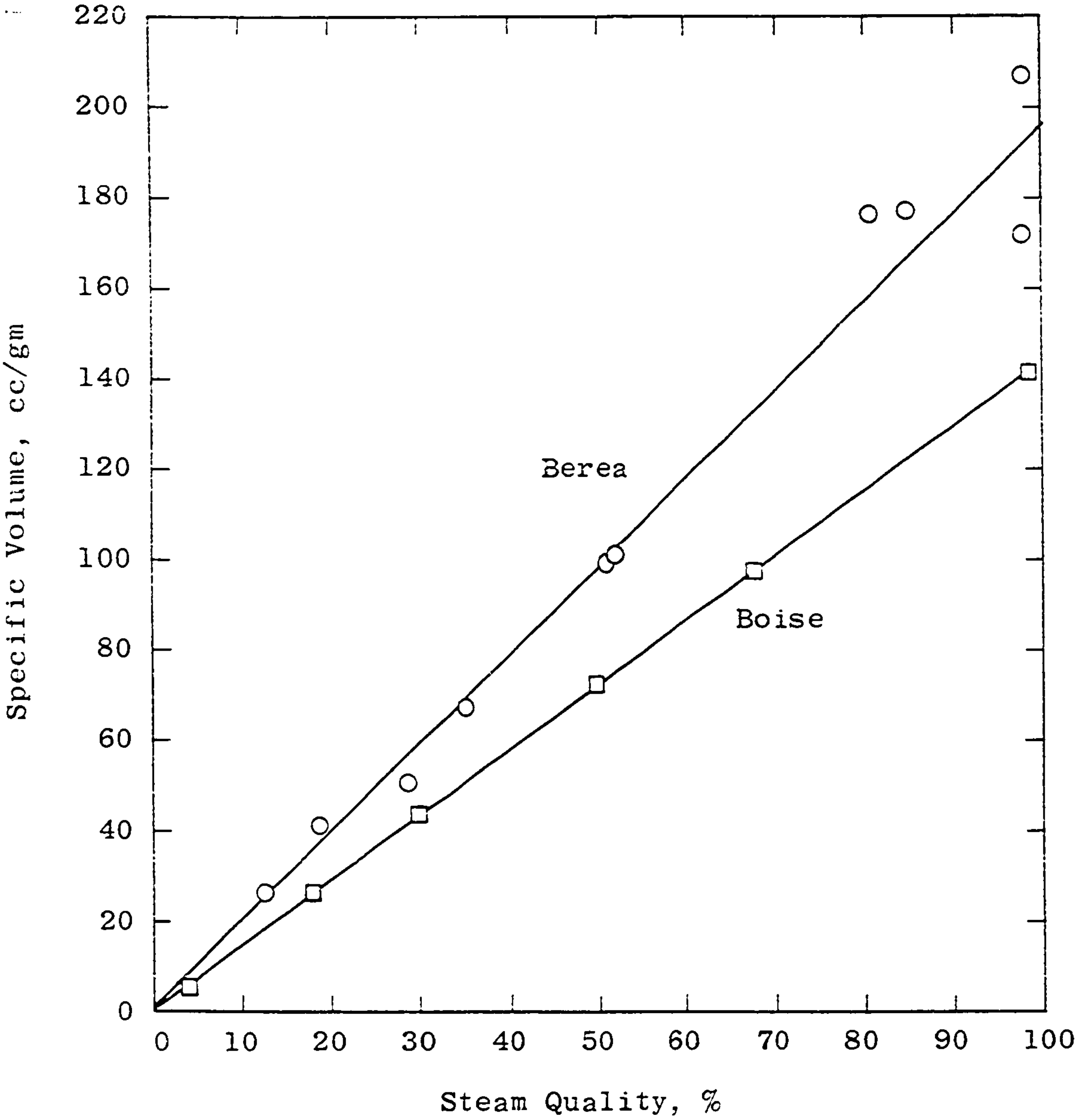

FIGURE 37 SPECIFIC VOLUME VS STEAM QUALITY AT AVERAGE EXPERIMENTAL CORE PRESSURE IN BOISE AND BEREA SANDSTONES

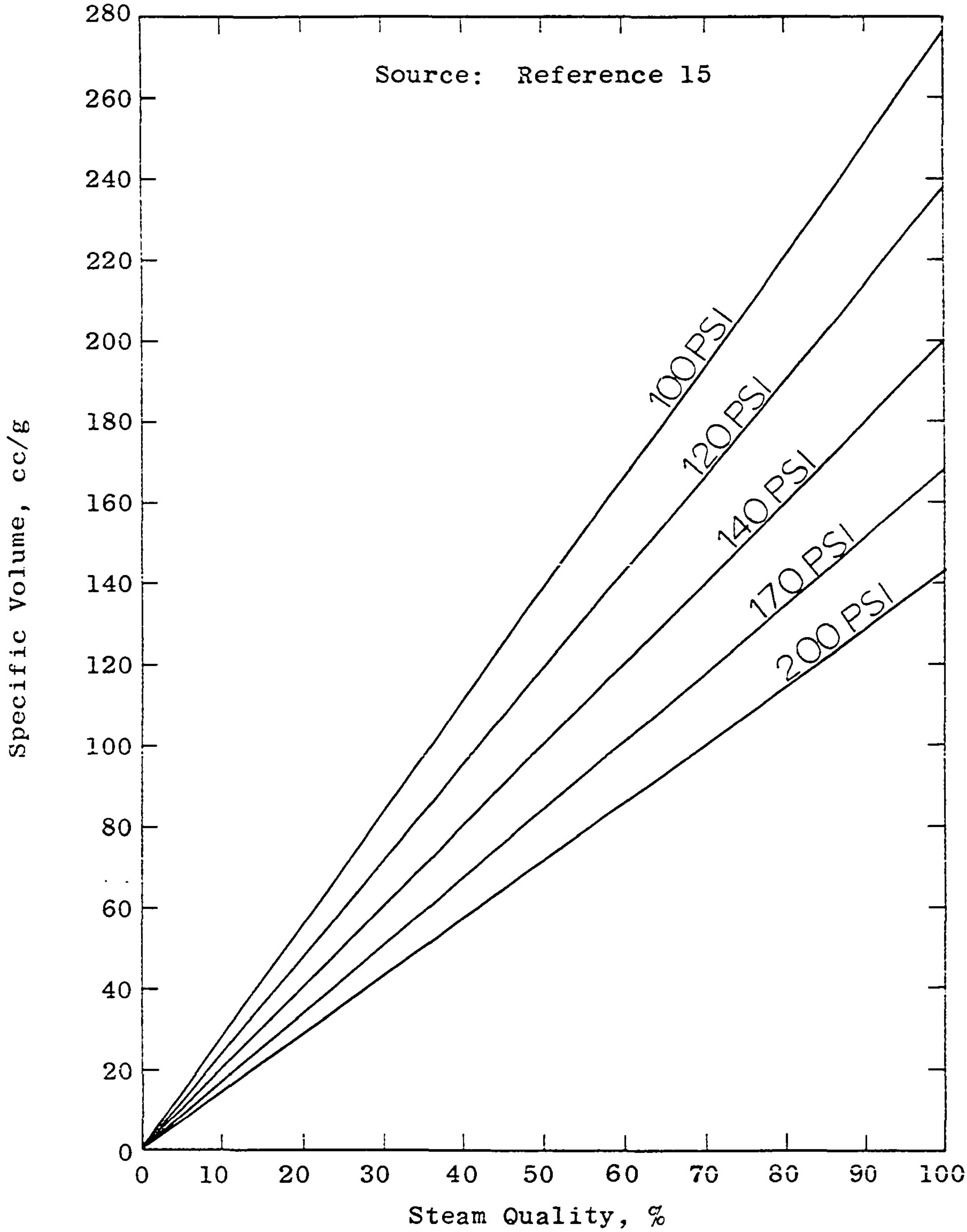

FIGURE 38 SPECIFIC VOLUME VS STEAM QUALITY AT VARIABLE PRESSURE

volume of the displacing steam is shown in Figures 39 and 40. A cross-plot through steam quality gave an identical recovery curve for the Boise which was expected on the basis of the good correlation in Figure 37. A similar cross-plot for the Berea shows the effect of the more erratic points in Figure 37 on the recovery curve. Figure 40 uses the actual specific volume values obtained from the floods and not the best-fit line shown on Figure 37. Maximum deviation from the quality-recovery curve is approximately 2% in terms of percent oil recovery.

Apparently what actually happens in the steamflood process is that a given pore is flooded many times by steam with respect to the corresponding produced liquid. The number of times a given pore is flooded increases as the ratio of specific volume of steam to specific volume of produced liquid.

Specific volume increases as quality increases at a constant pressure and as the experiments indicate recovery also increases. The average core pressure in the Boise experiments was slightly less than 200 psia while the average core pressure in the Berea were slightly over 140 psia at steady-state conditions. Figure 38 shows that as pressure decreases for constant quality steam the specific volume increases. This suggests that if the ultimate oil recovery is primarily a function of the dimensionless specific volume ratio, then the Berea should recover more

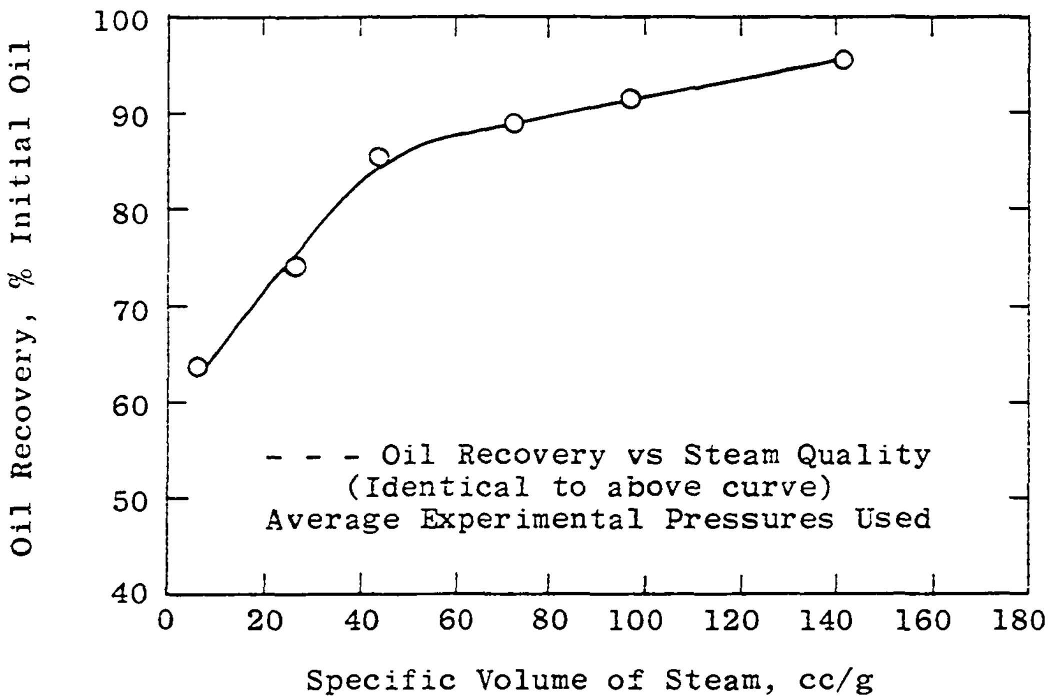

FIGURE 39 SPECIFIC VOLUME OF WET STEAM VS OIL RECOVERY FOR BOISE SANDSTONE

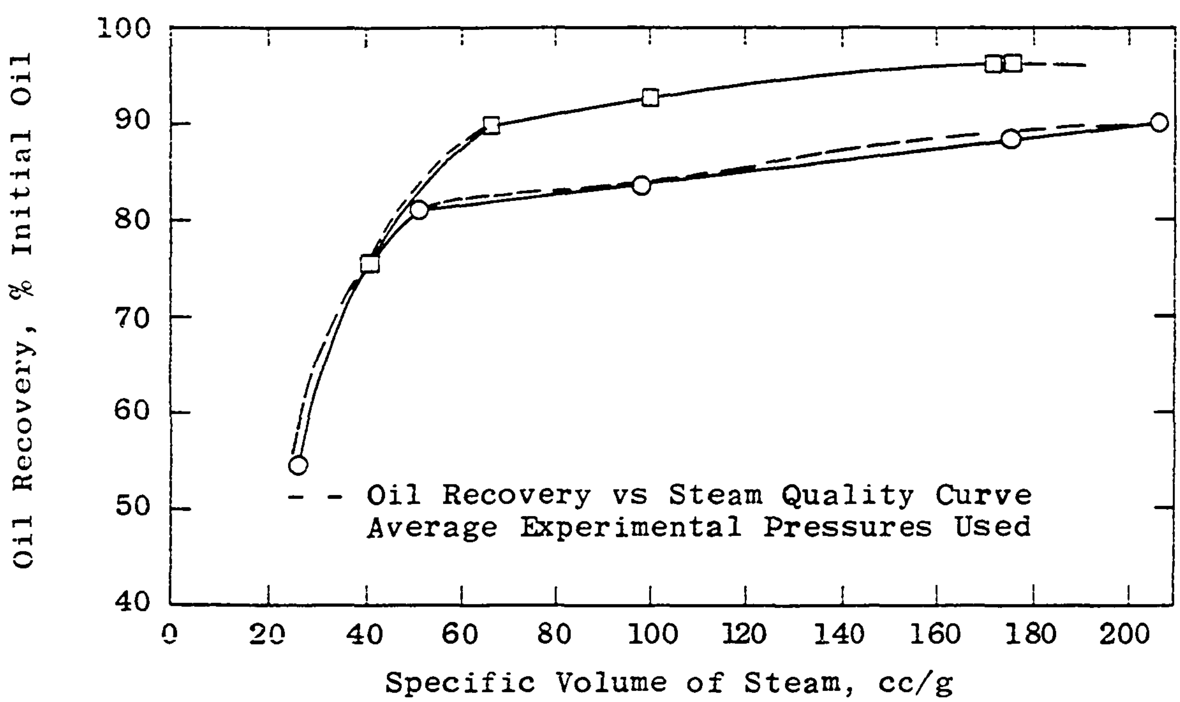

FIGURE 40 SPECIFIC VOLUME OF WET STEAM VS OIL RECOVERY FOR BEREA SANDSTONE

oil. The experiments verify this down to about 20% quality where possibly conventional relative permeability concepts in displacement becomes more dominant as the two-phase water mixture approaches liquid behavior in the smaller size pores.

CHAPTER VII

CONCLUSIONS

This study made a useful contribution to the knowledge of the steam displacement process. The high quality of equipment and its versatility were applied to obtain meaningful data. As a result of this study the following conclusions were reached for the subject experimental conditions.

1. Absolute permeability increased slightly with temperature for both the Boise and Berea sandstones. Data variation for the Boise was too large for any definite conclusions however a rate of permeability increase with temperature was estimated from the Berea to be 0.23 md/^{o}F.
2. The property characteristics of the porous media remained fairly constant during the experimental runs. Individual solvent and baking treatments showed no effect on porosity, however a slight increase in permeability was measured with baking.
3. Steam mobility decreased with quality for both

the high- and low-permeability cores without residual oil saturation; the decline was approximately twice as rapid for the more permeable Boise core.

4. No significant mobility discontinuities between under-saturated hot water and low quality steam appeared to exist for the cores evaluated.
5. Residual oil has a definite effect on steam mobility. Where steam mobility was measured on separate runs in the presence of residual oil saturation, the effect of that residual oil saturation decreased with quality decrease and increased with pore size as suggested by absolute permeability.
6. The K_{rw}/K_{ro} ratio increased with temperature for the Boise sandstone over the range of water saturations obtained. The K_{rw}/K_{ro} ratio decreased and then increased with temperature for the Berea sandstone with water saturation increase.
7. Individual relative permeability curves for both the Boise and Berea indicated a decrease in relative permeability to oil and water with temperature.
8. The oil recovery (expressed as percent of the initial oil) before steam breakthrough decreases with steam quality. The oil recovery at water

breakthrough is less than at steam breakthrough.

9. The effect of pore size on oil recovery with quality steam does not significantly affect total recovery. Surprisingly at low qualities, the smaller pore size, even with a larger volumetric amount of available liquid water, yielded a lower oil recovery.

10. When the steam displacement process is without the benefit of viscosity reduction and steam distillation, it was found that steam is still a very efficient displacing fluid.

11. The mobility of the displacing fluid (steam) decreased with quality which gave a more favorable mobility ratio for displacement. Yet the oil recovery also decreased with quality.

12. It is postulated that the fundamental steam displacement mechanism is the ratio of the specific volume of steam at its instantaneous displacement pressure to the specific volume of the produced liquid. This mechanism results in high displacement efficiency by flooding a given pore many times with steam relative to the corresponding produced liquid. Using this postulate as indicated in the text, the oil recovery results are satisfactorily explained.

13. An important conclusion from this investigation

was that a linear relation existed between steam quality and specific volume for the entire quality spectrum with variable residual oil saturation. This relation held for the pressure drops associated with both the Boise and Berea cores but the extension of this linearity with distance beyond the core lengths used in this study need investigation.

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APPENDICES

APPENDIX A

NOMENCLATURE

A = Cross-section area, cm^2

C = Isobaric heat capacity, Btu/g-^oF

D_c = Diameter of cylindrical core, cm

f = Fractional flow of time

H = Enthalpy, Btu/lbm

HL1 = Heat loss from generator to junction, Btu/lbm

HL2 = Heat loss from junction to core inlet, Btu/lbm

I_r = Relative injectivety, ratio of intake capacity at any point in a flood to the intake capacity of the system at the initiation of the flood,

$(u/\triangle P)/(u/\triangle P)_{initial}$

K = Absolute permeability, darcy

K_i = Effective permeability to phase i, darcy

K_{ri} = Relative permeability to phase i

L = Total length of system, cm

M = Mass rate, cc/sec

P = Pressure, atm

PV = Pore Volume

q = Volumetric flow rate, cc/sec

Q = Cumulative injection volume, PV

t = Time, sec

u = Average velocity in the pores, cm/sec

v = Specific volume, cc/g

X = Steam quality

$\emptyset$ = Porosity

ρ = Density, lbm/ft^3

μ = Viscosity, centipoise, cp

ΔP = Differential pressure, psid

Subscripts

avg = average

cw = cold water

f = fluid

g = vapor

o = oil

r = rock matrix

s = steam

shs = superheated steam

sw = saturated water

t = total

vap = vaporization

w = water

1,2 = inlet, outlet

APPENDIX B

SUMMARY OF EXPERIMENTAL RESULTS

TABLE B-1

SUMMARY OF EXPERIMENTAL RESULTS: ABSOLUTE STEAM MOBILITY IN BOISE SANDSTONE

Generator Conditions, ^{o}F/psia	Water Rates, cc/min. Gen.	Cold wtr.	Heat Losses, BTU/lbm Gen.-Junc.	Junc.-Inlet	Press. Diff., psid	Steam Quality, %	Steam Mobility, Darcy/cp
510/200	15.1	0	81	18	1.67	97.5	445
540/200	12.0	3.1	100	31	1.17	67.4	437
555/200	10.0	4.8	105	39	0.96	53.6	417
530/200	8.0	7.0	108	42	0.53	25.4	367
500/200	6.6	9.0	109	43	0.43	13.3	270
493/200	5.0	9.9	110	44	0.17	3.9	149

Temperature cold water = 72^{o}F

TABLE B-2

SUMMARY OF EXPERIMENTAL RESULTS: HOT WATER MOBILITY IN BOISE AND BEREA SANDSTONES

Sandstone	Water Temperature, °F	Water Rate, cc/min.	Pressure Differential, psid	Absolute Permeability, Darcy	Hot Water Mobility, Darcy/cp
Boise	72	31.0	1.04	9.97	10.4
Boise	168	21.5	0.27	10.65	28.1
Boise	225	21.2	0.20	10.52	39.9
Boise	303	21.1	0.15	9.98	53.8
Boise	348	24.7	0.15	10.25	64.9
Berea	80	16.0	10.18	0.527	0.62
Berea	205	16.0	3.53	0.543	1.84
Berea	300	16.0	2.23	0.577	3.05

TABLE B-3

SUMMARY OF EXPERIMENTAL RESULTS:

STEAM MOBILITY IN BOISE SANDSTONE WITH RESIDUAL OIL SATURATION FOR CONTINUOUS RUN 1

Generator Conditions, ^{o}F/psia	Water Rates, cc/min. Gen.	Water Rates, cc/min. Cold wtr.	Heat Losses, BTU/1bm Gen.-Junc.	Heat Losses, BTU/1bm Junc.-Inlet	Press. Diff., psid	ROS, %	Steam Quality, %	Steam Mobility, Darcy/cp
512/200	15.0	0	82	18	2.52	5.2	97.3	291
520/200	12.2	3.2	99	35	1.50	4.6	66.8	329
515/200	10.0	5.0	105	39	1.20	4.5	47.8	299
545/200	7.8	6.9	108	42	0.95	4.5	29.8	233
520/200	6.4	9.0	110	43	0.95	4.5	15.8	108

Temperature cold water = 76^{o}F

ROS = Residual oil saturation, percent initial oil

TABLE B-4

SUMMARY OF EXPERIMENTAL RESULTS:

STEAM MOBILITY IN BOISE SANDSTONE WITH RESIDUAL OIL SATURATION FOR CONTINUOUS RUN 2

Generator Conditions, ^{o}F/psia	Water Rates, cc/min. Gen.	Water Rates, cc/min. Cold wtr.	Heat Losses, BTU/lbm Gen-Junc.	Heat Losses, BTU/lbm Junc-Inlet	Press. Diff., psid	Steam Quality, %	Steam Mobility, Darcy/cp
505/200	14.8	0.0	83	19	1.98	96.7	364
545/200	11.8	3.1	100	32	1.91	67.3	265
522/200	10.0	4.8	105	39	1.76	49.3	210
545/200	8.0	6.9	108	42	1.50	30.0	152
548/200	6.9	9.0	109	43	1.42	15.6	98
550/200	4.8	9.7	112	45	0.74	2.2	27

Residual Oil Saturation ≐ 4.5% Initial Oil

Temperature cold water = 75^{o}F

TABLE B-5

SUMMARY OF EXPERIMENTAL RESULTS:

STEAM MOBILITY IN BOISE SANDSTONE WITH ZERO RESIDUAL OIL SATURATION FOR CONTINUOUS RUN 3

Generator Conditions, ^{o}F/psia	Water Rates, cc/min.		Heat Losses, BTU/lbm		Press. Diff., psid	Steam Quality, %	Steam Mobility, Darcy/cp
	Gen.	Cold wtr.	Gen.-Junc.	Junc.-Inlet			
490/200	15.5	0	80	17	2.18	96.3	344
540/200	11.8	3.2	100	33	2.08	66.2	243
525/200	10.0	5.0	105	38	2.03	48.2	184
515/200	6.1	9.1	110	43	1.36	11.4	68
545/200	5.0	10.0	110	44	0.77	3.1	41
Repeatability Check at Conclusion of Oil Recovery Experiments							
510/200	15.1	0	71	18	2.10	98.5	352
535/200	12.0	3.1	98	31	2.14	67.6	238

TABLE B-6

SUMMARY OF EXPERIMENTAL RESULTS:

STEAM MOBILITY IN BOISE SANDSTONE WITH RESIDUAL OIL SATURATION

Water Rates, cc/min. Gen.	Cold wtr.	Residual Oil Saturation,%*	Pressure Diff., psid	Steam Quality, %	Steam Mobility, Darcy/cp
12.0	3.2	8.7	3.15	67.3	164
10.0	5.0	11.1	2.90	49.6	129
8.0	7.2	14.8	2.26	29.8	103
6.1	9.0	26.0	2.16	17.8	64
5.0	10.0	36.2	1.49	3.8	21
15.0	0	4.2	2.28	98.3	325

* Percent initial oil

TABLE B-7

SUMMARY OF EXPERIMENTAL RESULTS:

ABSOLUTE STEAM MOBILITY IN BEREA SANDSTONE

Generator Conditions, °F/psia	Water Rates, cc/min. Gen.	Water Rates, cc/min. Cold wtr.	Heat Losses, BTU/lbm Gen.-Junc.	Heat Losses, BTU/lbm Junc.-Inlet	Press. Diff., psid	Steam Quality, %	Steam Mobility, Darcy/cp
543/199	9.1	0	102	40	48.8	94.9	13.05
528/199	7.9	1.4	103	41	40.3	74.3	12.00
544/198	5.9	3.2	106	43	34.6	46.6	8.37
545/199	5.0	4.5	106	44	30.3	29.7	6.58
538/196	4.2	7.1	106	56	10.4	8.2	5.32

Temperature cold water = 78°F

TABLE B-8

SUMMARY OF EXPERIMENTAL RESULTS:

STEAM MOBILITY IN BEREA SANDSTONE WITH RESIDUAL OIL SATURATION

Water Rates, cc/min. Gen.	Water Rates, cc/min. Cold wtr.	Residual Oil Saturation,%*	Pressure Diff., psid	Average Steam Quality,%	Steam Mobility, Darcy/cp
8.8	0.0	9.8	71.1	98.0	10.00
8.0	1.4	11.6	78.5	80.9	8.23
6.1	3.1	16.3	56.8	50.6	6.24
5.0	4.5	17.8	35.7	29.3	5.27
4.2	7.1	45.7	68.2	12.6	1.69
8.8	0.0	3.9	48.4	98.0	12.00
4.2	7.1	24.7	73.6	18.9	2.44
5.8	3.1	7.0	57.5	52.0	6.05
7.8	1.3	3.2	68.2	85.0	9.76
5.0	4.5	10.0	48.5	34.9	5.00

* Percent initial oil

TABLE B-9

SUMMARY OF EXPERIMENTAL RESULTS:

COLD WATERFLOOD FOLLOWED BY STEAMFLOOD

Generator Conditions, ^{o}F/psia	Water Rates, cc/min. Gen.	Water Rates, cc/min. Cold wtr.	Heat Losses, BTU/lbm Gen.-Junc.	Heat Losses, BTU/lbm Junc.-Inlet	Steam Quality, %	Oil Recovery, % Initial Oil
77/200	-	20.5	(Cold Waterflood)			55.2
512/200	15.0	0.0	82	18	97.3	94.8

Initial water saturation = 31.2 percent pore volume

Temperature cold water = $77^{o}F$

TABLE B-10

SUMMARY OF EXPERIMENTAL RESULTS:

OIL RECOVERY VS STEAM QUALITY FOR BOISE SANDSTONE

Generator Conditions, °F/psia	Water Rates, cc/min. Gen.	Water Rates, cc/min. Cold wtr.	Heat Losses, BTU/lbm Gen.-Junc.	Heat Losses, BTU/lbm Junc.-Inlet	Injected Steam Quality,%	Initial Wtr. Sat., % PV	Oil Recovery, Percent Initial Oil
536/200	15.0	0	82	18	98.3	28.5	95.2(95.8)
512/200	15.0	0	82	18	97.3	31.2	94.8*
550/200	12.0	3.2	100	31	67.3	28.0	89.8(91.3)
550/200	10.0	5.0	103	38	49.6	28.7	87.9(89.0)
550/200	8.0	7.2	108	42	29.8	28.6	83.8(85.2)
560/200	6.1	9.0	110	44	17.8	28.5	69.3(74.0)
565/200	5.0	10.0	110	44	3.8	29.7	54.2(63.8)

* Run following cold waterflood.

Value in parenthesis is oil recovery with annulus temperature gradient superimposed on core temperature gradient.

TABLE B-11

SUMMARY OF EXPERIMENTAL RESULTS:

OIL RECOVERY VS STEAM QUALITY FOR BEREA SANDSTONE

Generator Conditions, ^{o}F/psia	Water Rates, cc/min. Gen.	Cold wtr.	Heat Losses, BTU/lbm Gen-Junc.	Junc-Inlet	Average Steam Quality,%	Initial Wtr. Sat., % PV	Oil Recovery, Percent Initial Oil
565/199	8.8	0	101	40	98.0	38.0	90.2
525/196	8.0	1.4	103	42	80.9	34.8	88.4
545/195	6.1	3.1	105	44	50.6	36.0	83.7
542/197	5.0	4.5	106	44	29.3	36.8	82.2
533/197	4.2	7.1	106	45	12.6	37.2	54.3

TABLE B-12

SUMMARY OF EXPERIMENTAL RESULTS:

OIL RECOVERY VS STEAM QUALITY FOR BEREA SANDSTONE (ANNULUS HEAT-LOSS CHANGE)

Core Water Rate, cc/min.	Inlet Temp. $^{\circ}$F Core/Annulus	Outlet Temp. $^{\circ}$F Core/Annulus	Pressure, psia Core Outlet/Ann.	Annulus Heat Loss, BTU/lbm	Core Inlet Steam Quality,%	Core Exit Steam Quality,%	Avg. Steam Quality,%	Oil Recovery, % Initial Oil
8.8	382/382	352/372	130.0/350	30.0	95.9	SHS*	98.0	96.1
11.3	383/383	302/364	69.0/350	24.0	7.9	29.9	18.9	75.3
8.9	383/382	321/368	90.7/350	30.0	44.4	59.5	52.0	93.1
9.1	383/382	308/368	74.5/350	0.0	74.6	95.3	85.0	96.8
9.5	384/380	329/368	101.5/350	30.0	29.1	40.7	34.9	90.0

* Superheated Steam

APPENDIX C

DERIVATION OF SATURATION EQUATION FOR RELATIVE PERMEABILITY

The Buckley-Leverett equation may be written for each of 2 phases as:

$$\frac{dx}{dt} = \frac{q_t}{\emptyset A} \frac{df_w}{dS_w}$$

$$\frac{dx}{dt} = \frac{q_t}{\emptyset A} \frac{df_o}{dS_o} \qquad (1)$$

It is assumed that the water is injected at a constant rate and that the oil and water are incompressible and immiscible.

At water breakthrough, the boundary condition on the core inlet of

$$f_{o1} = 0$$

$$f_{w1} = 1 \qquad (2)$$

is reasonable for some δ distance from the inlet.

For a linear core system of length L with water displacing oil, we have by definition after water breakthrough,

$$S_{oavg} = \frac{\int_1^2 S_o dx}{\int_1^2 dx} \tag{3}$$

Integrating equation (3) by parts:

$$LS_{oavg} \quad \int_1^2 S_o dx = xS_o \Big|_1^2 - \int_1^2 x dS_o \tag{4}$$

If equation (1) is integrated with respect to time,

$$x = \frac{q_t t}{\emptyset A} \frac{df_o}{dS_o} \tag{5}$$

Then by substituting equation (5) into equation (4) we obtain:

$$LS_{o\ avg} = xS_o \Big|_1^2 - \int_1^2 \frac{q_t t}{\emptyset A} \frac{df_o}{dS_o} \cdot dS_o$$

$$= L\left(S_{o2} - S_{o1}\right) - \frac{q_t t}{\emptyset A} \left(f_{o2} - f_{o1}\right) \tag{6}$$

But by equation (2) $f_{o1} = 0$

which also implies $S_{o1} = 0$, then:

$$LS_{o\ avg} = LS_{o2} - \frac{q_t t}{\emptyset A} f_{o2}$$

$$S_{o\ avg} = S_{o2} - \frac{q_t t}{\emptyset AL} f_{o2}$$

or

$$S_{o2} = S_{o\ avg} + Qf_{o2} \tag{7}$$

which is the desired saturation equation.

This equation can also be derived by using a mass balance on oil contained in the core at a time t as:

$$\emptyset A \int_1^2 S_o dx = \emptyset AL \left(1 - S_{wi}\right) - Q_o \tag{8}$$

This equation states that the oil contained in the core at some time t equals the oil in the core at t = o minus the cumulative production at time t. Integrating the left side of equation (8) by parts and substituting the Buckley-Leverett equation in the form,

$$x = \frac{q_t}{\emptyset A} \frac{df_o}{dS_o}$$

as before, we obtain:

$$Ax\emptyset S_o \Big|_1^2 - \emptyset A \int_1^2 \frac{q_t t}{\emptyset A} \frac{df_o}{dS_o} \cdot dS_o = \emptyset AL \left(1 - S_{wi}\right) - Q_o$$

$$AL\emptyset S_{o2} - q_t t \ f_{o2} = \emptyset AL \left(1 - S_{wi}\right) - Q_o \tag{9}$$

Dividing both sides by the pore volume, ØAL, we obtain:

$$S_{o2} = \frac{q_t t}{\emptyset AL} \ f_{o2} + \frac{\emptyset AL \left(1 - S_{wi}\right) - Q_o}{\emptyset AL}$$

$$S_{o2} = Q \ f_{o2} + S_{o \ avg} \tag{10}$$

which is the same as equation (7).

APPENDIX D

DERIVATION OF RELATIVE PERMEABILITY EQUATIONS

For a particular instant during a displacement experiment the pressure drop across the system of length L may be expressed as the integral:

$$\Delta p = -\int_0^L \frac{\partial p}{\partial x}\, dx \tag{1}$$

Darcy's equation may be expressed as:

$$f_o q_t = -\frac{K K_{ro} A}{\mu_o} \frac{\partial p}{\partial x} \tag{2}$$

Solving equation (2) for $\frac{\partial p}{\partial x}$ and substituting into equation (1):

$$\Delta p = \frac{q_t \mu_o}{KA} \int_0^L \frac{f_o}{K_{ro}}\, dx \tag{3}$$

The Buckley-Leverett equation can be expressed as,

$$\Delta x = \frac{q_t \Delta t}{A\emptyset} \frac{df}{dS} \tag{4}$$

and as a ratio between distances:

$$\frac{x}{L} = \frac{\dfrac{q_t t}{A\emptyset} \dfrac{df_o}{dS_o}}{\dfrac{q_t t}{A\emptyset} \dfrac{df_{o2}}{dS_{o2}}} \tag{5}$$

If we let

$$f' = \frac{df_o}{dS_o} \text{ and } f_2' = \frac{df_{o2}}{dS_{o2}} \tag{6}$$

then

$$\frac{x}{L} = \frac{f'}{f_2'} \text{ and } dx = \frac{L}{f_2'} \ df' \tag{7}$$

Substituting the relation for dx from equation (7) into equation (3) we obtain:

$$\Delta p = \frac{q_t \mu_o}{KA} \int_o^{f_2'} \frac{f_o}{K_{ro}} \left(\frac{L}{f_2'} \ df' \right)$$

$$= \frac{q_t \mu_o}{KAf_2'} \int_o^{f_2'} \frac{f_o}{K_{ro}} \ df' \tag{8}$$

or

$$\int_{0}^{f_2'} \frac{f_o}{K_{ro}}\, df' = \frac{\Delta pKA}{q_t \mu_o L}\, f_2' \tag{9}$$

If we take the derivative of this equation with respect to f_2' as the only independent variable considered, then we can use ordinary derivatives with the result:

$$\frac{d}{df_2'} \int_{0}^{f_2'} \frac{f_o}{K_{ro}}\, df' = \int_{0}^{f_2'} \frac{\partial}{\partial f_2'} \left(\frac{f_o}{K_{ro}}\, df' \right) + \frac{f_{o2}}{K_{ro}} \frac{d}{df_2'} \left(f_2' \right)$$

$$= \frac{d}{df_2'} \left(\frac{\Delta pKA}{q_t \mu_o L}\, f_2' \right)$$

and

$$\frac{f_{o2}}{K_{ro}} = \frac{d}{df_2'} \left(\frac{\Delta pKA\, f_2'}{q_t \mu_o L} \right) \tag{10}$$

or in more useful form by noting

$$L = \frac{q_t t}{A\emptyset} \frac{df_{o2}}{dS_{o2}}$$

where

$$\frac{df_{o2}}{dS_{o2}} = f_2' = \frac{LA\emptyset}{q_t t} = \frac{1}{Q}$$

Then substituting this relation in equation (10) the result is:

$$\frac{f_{o2}}{K_{ro}} = \frac{d\left(\frac{\Delta pKA}{q_t \mu_o LQ}\right)}{d\left(\frac{1}{Q}\right)} \tag{11}$$

In the right hand side of equation (11) are quantities which are all measurable from experimental data. The value of K_{ro} can be obtained by dividing f_{o2} by the slope of a plot of:

$$\frac{1}{Q} \text{ vs } \frac{\Delta pKA}{q_t \mu_o LQ} \tag{12}$$

The same procedure can be followed for the water phase by changing subscripts with the result:

$$\frac{f_{w2}}{K_{rw}} = \frac{d\left(\frac{\Delta pKA}{q_t \mu_w LQ}\right)}{d\left(\frac{1}{Q}\right)} \tag{13}$$

However with only two phases it is simpler to use the relation,

$$K_{rw} = \left(\frac{1-f_o}{f_o}\right) K_{ro} \frac{\mu_w}{\mu_o} \tag{14}$$

which is developed by applying Darcy's equation to each phase:

$$f_o\, q_t = -\frac{KK_{ro}A}{\mu_o} \frac{\partial p_o}{\partial x} \tag{15}$$

$$f_w \, q_t = - \frac{KK_{rw}A}{\mu_w} \frac{\partial p_w}{\partial x} \tag{16}$$

Then dividing equation (15) by equation (16) and recognizing that $\frac{\partial p_o}{\partial x} = \frac{\partial p_w}{\partial x}$ for stabilized oil displacement the desired equation is obtained:

$$\frac{f_o}{f_w} = \frac{K_{ro}/\mu_o}{K_{rw}/\mu_w}$$

$$K_{rw} = \left(\frac{1-f_o}{f_o}\right) K_{ro} \, \frac{\mu_w}{\mu_o} \, . \tag{17}$$

APPENDIX E

CALCULATION OF RELATIVE PERMEABILITY CURVES FROM COLD WATER DISPLACEMENT DATA FOR BEREA SANDSTONE

Given Data:

Hot waterflood at 315°F

Pore volume = 262.0 cc

Initial water saturation = 0.398

Viscosity ratio = μ_w/μ_o = 0.343

Absolute permeability = 0.410 Darcy

Cross-sectional area of core = 19.85 cm^2

Length of core = 31.7 cm (dist. between press. taps)

Viscosity of oil at test conditions = .40 cp

Constant injection rate = 9.7 cc/min

Waterflood tabulated data of: (1) Cumulative water injected, (2) Cumulative oil produced (3) Corresponding differential-pressure readings for pressure drop across the core.

Method of Solution:

We approximate the relation

$$\frac{f_{o2}}{K_{ro}} = \frac{d\left(\frac{\Delta PKA}{q_t \mu_o LQ}\right)}{d\left(\frac{1}{Q}\right)} \doteq \frac{\Delta\left(\frac{\Delta P}{q_t \mu_o L/KA} \cdot \frac{1}{Q}\right)}{\Delta\left(\frac{1}{Q}\right)}$$

$$= \frac{\Delta\left(\frac{1}{I_r} \cdot \frac{1}{Q}\right)}{\Delta\left(\frac{1}{Q}\right)}$$

by assuming a straight line between data points for a numerical solution adaptable to the computer rather than a graphical plot.

Then

$$K_{ro} \doteq \frac{f_{o2} \quad \Delta\left(\frac{1}{Q}\right)}{\Delta\left(\frac{1}{I_r Q}\right)}$$

where

$$f_{o2} = \frac{\Delta S_w}{\Delta Q}$$

The basic relation

$$K_{rw} = K_{ro}\left(\frac{1-f_{o2}}{f_{o2}}\right)\frac{\mu_w}{\mu_o}$$

is then used to calculate the relative permeability to water.

Solution

The complete results are shown tabulated in Tables E-1 and E-2. An example calculation is given for Run 2.

$$f_{o2} = \frac{\Delta S_w}{\Delta Q} = \frac{0.01812}{0.02213} = 0.8190$$

$$\frac{1}{I_r} = \frac{\Delta P}{(q_t \mu_o L)/(KA)} = \frac{54.3}{23.6} = 2.301$$

$$K_{ro} = f_{o2} \frac{\Delta\left(\frac{1}{Q}\right)}{\Delta(1/I_r Q)} = (0.8190)\,\frac{(0.4673)}{(1.077)}$$

$$= 0.3553$$

$$K_{rw} = K_{ro}\left(\frac{1-f_{o2}}{f_{o2}}\right)\frac{\mu_w}{\mu_o}$$

$$= (0.3553)\ \frac{0.1810}{0.8190}\ (0.3430)$$

$$= 0.0269$$

$$Q_{avg} = \frac{0.206 + 0.229}{2} = 0.2175$$

$$S_{w\ avg} = \frac{0.576 + 0.594}{2} = 0.5850$$

(Note: Average water saturation as used here means the average at the midpoint of the particular time interval for the corresponding average core saturations.)

$$S_{w2} = S_{w\ avg} - Q_{avg}\ f_{o2}$$

$$= 0.5850 - (0.2175)\ (0.8190)$$

$$= 0.5850 - .1780$$

$$= 0.4070$$

TABLE E-1

PRODUCTION DATA: BEREA COLD WATERFLOOD

Run No.	Cum. Water Injected, PV	Cum. Oil Prod., cc	S_w (Avg. in Core)	Diff. Press., psid
1	0.206	46.75	0.576	54.31
2	0.229	51.50	0.594	54.30
3	0.244	54.95	0.607	54.29
4	0.263	56.10	0.612	54.26
5	0.282	57.55	0.617	54.21
6	0.297	58.10	0.619	54.20
7	0.319	58.30	0.620	54.19
8	0.358	58.55	0.621	54.11
9	0.396	58.65	0.621	54.07
10	0.433	58.66	0.621	54.00

TABLE E-2

CALCULATION OF RELATIVE PERMEABILITY CURVES FROM COLD WATER DISPLACEMENT DATA FOR BEREA SANDSTONE

Run No.	(1) ΔS_w	(2) ΔQ	(3) f_{o2}	(4) $1/I_r$	(5) $1/Q$	(6) $1/(QI_r)$	(7) $\Delta(1/Q)$
1				2.3013	4.8339	11.1242	
2	0.0181	0.0221	0.8190	2.3008	4.3667	10.0470	0.4673
3	0.0132	0.0156	0.8415	2.3004	4.0874	9.4027	0.2793
4	0.0044	0.0187	0.2347	2.2991	3.7971	8.7301	0.2903
5	0.0055	0.0187	0.2959	2.2970	3.5453	8.1437	0.2518
6	0.0021	0.0156	0.1341	2.2966	3.3590	7.7142	0.1863
7	0.0008	0.0217	0.0351	2.2962	3.1302	7.1876	0.2287
8	0.0009	0.0385	0.0247	2.2928	2.7932	6.4042	0.3370
9	0.0004	0.0389	0.0098	2.2911	2.5192	5.7718	0.2739
10	0.0001	0.0366	0.0010	2.2881	2.3063	5.2772	0.2129

TABLE E-2 (Cont.)

CALCULATION OF RELATIVE PERMEABILITY CURVES FROM COLD WATER DISPLACEMENT DATA FOR BEREA SANDSTONE

Run No.	(8) $\Delta \frac{1}{QI_r}$	(9) $\frac{\text{Col (7)}}{\text{Col (8)}}$	(10) K_{ro}	(11) $S_{w\ avg}$	(12) Q_{avg}	(13) $f_{o2}\ Q_{avg}$	(14) S_{w2}
1							
2	1.0772	0.4338	0.3553	0.5855	0.2179	0.1785	0.4070
3	0.6444	0.4334	0.3647	0.6011	0.2368	0.1993	0.4019
4	0.6725	0.4316	0.1013	0.6099	0.2540	0.0596	0.5503
5	0.5864	0.4294	0.1270	0.6149	0.2727	0.0807	0.5342
6	0.4295	0.4339	0.0582	0.6187	0.2899	0.0389	0.5798
7	0.5267	0.4343	0.0152	0.6201	0.3086	0.0108	0.6093
8	0.7834	0.4302	0.0106	0.6210	0.3387	0.0084	0.6126
9	0.6324	0.4332	0.0042	0.6217	0.3775	0.0037	0.6180
10	0.4946	0.4304	0.0004	0.6219	0.4153	0.0004	0.6214

TABLE E-2 (Cont.)

CALCULATION OF RELATIVE PERMEABILITY CURVES FROM COLD WATER DISPLACEMENT DATA FOR BEREA SANDSTONE

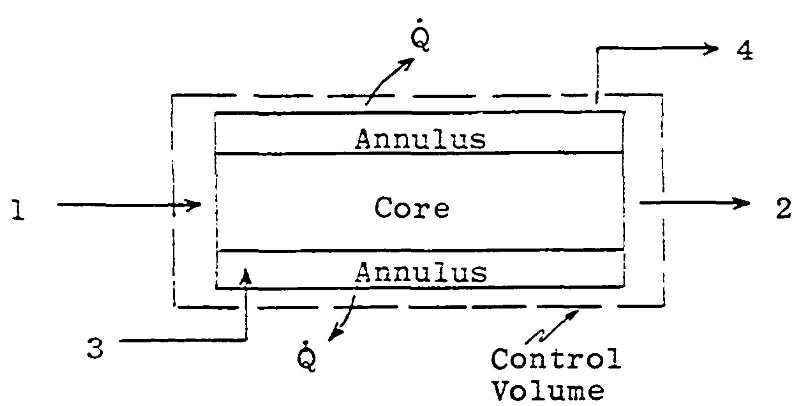
	(15)	(16)	(17)	(18)	(19)	(20)
Run No.	f_{w2}	$(f_{w2}/f_{o2})(K_{ro})$	K_{rw}	K_{rw}/K_{ro}	K_w	K_o
1						
2	0.1810	0.0785	0.0269	0.0758	0.0110	0.1456
3	0.1585	0.0687	0.0236	0.0646	0.0097	0.1495
4	0.7653	0.3303	0.1133	1.1185	0.0464	0.0415
5	0.7041	0.3023	0.1037	0.8161	0.0425	0.0521
6	0.8658	0.3757	0.1289	2.2139	0.0528	0.0239
7	0.9649	0.4191	0.1437	9.4325	0.0589	0.0062
8	0.9752	0.4196	0.1439	13.5142	0.0590	0.0044
9	0.9902	0.4289	0.1471	34.6430	0.0603	0.0017
10	0.9989	0.4300	0.1475	328.9371	0.0605	0.0002

APPENDIX F

CALCULATION OF EXIT STEAM QUALITY WITH EXPERIMENTAL ANNULUS HEAT LOSS DATA

In this section an energy analysis of the core-holder system is made to show how the annulus heat loss is determined for a given annulus water injection rate. Then an example calculation is given to show how the exit steam quality may be calculated using the annulus heat-loss data.

A. Determine Annulus Heat Loss



Given Data:

$\dot{m}_1 = \dot{m}_2 = 9.1$ g/min $\qquad \dot{m}_3 = \dot{m}_4 = 65.2$ g/min

$T_3 = 382^\circ F$

$T_4 = 374^\circ F$

$P_3 = P_4 = 350$ psia

Assumptions:

1. Steady-state, steady-flow conditions
2. Negligible kinetic and potential energy terms
3. Negligible pressure gradient in annulus

Calculation:

The first law may be written with the above assumptions for the control volume as:

$$\sum \dot{m}_i h_i - \sum \dot{m}_o h_o - \dot{Q} = 0 \tag{1}$$

where $\dot{Q}$ into the control volume is positive.

Then we have:

$$\dot{m}_1 h_1 + \dot{m}_3 h_3 - \dot{m}_2 h_2 - \dot{m}_4 h_4 - \dot{Q} = 0$$

$$Q = \frac{\dot{Q}}{\dot{m}_1} = h_1 - h_2 + \frac{\dot{m}_3}{\dot{m}_1}(h_3 - h_4) \tag{2}$$

For adiabatic conditions on the core, $h_1 = h_2$ and using reference 12:

$$Q = \frac{\dot{m}_3}{\dot{m}_1}(h_3 - h_4) = \frac{65.2}{9.1}(356-348) \tag{3}$$

$$Q = 65 \text{ Btu/lbm}$$

B. Calculation of Exit Quality

Given Data:

$\dot{m}_1$ = 8.8 g/min	P_1 = 200 psia
$\dot{m}_3$ = 78 g/min	P_2 = 130 psia
T_1 = 382°F	$P_3 = P_4$ = 350 psia
T_2 = 352°F	h_1 = 1163 Btu/lbm
T_3 = 382°F	Q = 30 Btu/lbm
T_4 = 372°F	

Substituting the given data into equation (2) and solving for h_2:

$$h_2 = h_1 + \frac{\dot{m}_3}{\dot{m}_1} (h_3 - h_4) - Q$$

$$= 1163 + \frac{78}{8.8} (356-345) - 30$$

$$= 1163 + 98 - 30 = 1231 \text{ Btu/lbm}$$

Using

h_2 = 1232 Btu/lbm

P_2 = 130 psia

We see that we have superheated steam at the outlet because saturated vapor at 130 psia has an enthalpy of 1192 Btu/lbm. We would have known that we had superheated steam at the outlet by examining the outlet core conditions of

T_2 = 352 °F

P_2 = 130 psia

which is superheated steam with H = 1195 Btu/lbm.

Therefore our analysis is in error by

$$\frac{1232 - 1195}{1195} \times 100 = 3.10\%$$

Using an average enthalpy of

$$\frac{1195 + 1163}{2} = 1178 \text{ Btu/lbm}$$

at an average core pressure of

$$\frac{200 + 130}{2} = 165 \text{ psia}$$

we have an average steam quality of:

$$X = \frac{1178 - 338}{857}$$

$$= 98.0\%$$

APPENDIX G

CALCULATION OF AVERAGE HEAT FLUX FROM BOISE SANDSTONE CORE

A gross heat balance on the core may be stated as:

Rate of Heat Injected - Rate of Heat Accumulation

= Rate of Heat Lost.

Symbolically this can be expressed as:

$$H_i - V_a A \Delta T \left[(1 - \emptyset) \rho_r C_r + \emptyset \rho_s \frac{H(x)}{\Delta T} \right] = \pi D_c L Q$$

where Q is the average heat flux from the core into the bounding media and V_a is the average steam-front velocity.

<u>Data From Experimental Conditions</u>

$L = 55.7$ cm | $\rho_r = 1.82$ g/cm^3 | $A = 22.1$ cm^2

$D_c = 5.33$ cm | $C_r = 0.00044 \frac{\text{Btu}}{\text{g-}^\circ\text{F}}$ (ref. 43)

T Gen. = 535°F | Flood Time = 23.3 min.

T Junc. = 391°F | $v_{cw} = 1.0029 \frac{\text{cc}}{\text{g}}$ @ 70°F

P = 200 psia | Porosity = 28.2%

Water Rate = 15.1 cc/min

$v_s = 141.5$ cc/g

HL_1 = 83 Btu/lbm $\rho_s = .00707 \frac{g}{cc}$

HL_2 = 18 Btu/lbm H_{ref} = H @ 75^{o}F & 200 psia

Calculation

$$X = \frac{1187-355}{843}(100) = 98.8\%$$

$$H_t = 1288-83-18 = 1187 \text{ Btu/lbm}$$

$$H(x) = \frac{1187-44}{453} = 2.53 \text{ Btu/g}$$

$$H_i = (2.53)(15.1)/1.0029 = 38.1 \text{ Btu/min}$$

Substituting in heat balance equation and solving for Q:

$$(38.1) - \left(\frac{55.7}{23.3}\right)(22.1)(382-75)\Big[(0.718)(1.82)$$

$$(0.00044) + (0.282)(0.00707)\left(\frac{2.53}{307}\right)\Big]$$

$$= (3.14)(5.33)(55.7)\ Q$$

Then $Q = \underline{\underline{0.0280 \text{ Btu/min-cm}^2}}$