DOE/ET/27146--T16

DE82 021792

MASTER

REPORT

DOE/ET/27146-T16

ENHANCEMENT OF HEAT PRODUCTION THROUGH SELECTIVE SCALING

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UNITED STATES DEPARTMENT OF ENERGY

DIVISION OF GEOTHERMAL ENERGY

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DATE OF ISSUANCE: AUGUST 16, 1982

VR REPORT NO: 82-08-16

SIGNATURE(S):

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PREAMBLE

The United States Department of Energy, Division of Geothermal Energy (DOE/DGE) awarded Vetter Research (VR) a contract to perform research work related to the injection and reinjection problems in Geothermal Operations. This Contract (No. DE-AC03-79ET27146) is entitled: "Injection, Injectivity and Injectability in Geothermal Operations". The present report is one of the deliverables under this DOE/DGE contract. The present report deals with the subject of selective scaling as a means of heat recovery from a geothermal reservoir.

The report discusses some conceptual modelling principles that might be utilized in accomplishing heat mining from geothermal reservoirs. The report also summarizes some of the literature information pertinent to the subject.

1.0 ABSTRACT

The heat-depleted brine has to be reinjected whether it is for technical, economical, environmental and/or legal purposes. The reinjection of this heat-depleted brine can actually aid in extending the geothermal resource by extracting additional heat energy from the geothermal reservoir. However, there are many problems related to injectivity and injectibility in a geothermal field. The major drawback is the dread of an early breakthrough of the heat depleted brine at the production wells. We believe that this drawback may be overcome through selective scaling. The present report is a summary of the results of investigation into the feasibility of such selective scaling.

Selective scaling is defined here as the process of intentionally precipitating large quantities of chemical compounds at selected locations, such as high permeability streaks or fractures, for the purpose of retarding the flow of injection fluids through these flow channels. Such flow retardation will increase the residence time of the injected fluids in the reservoir by a more suitable "heat sweep" thereby enhancing the heat extraction from the geothermal reservoir.

Three different methods of selective scaling are discussed in this report. These methods are:

1. The injection of a thermodynamically unstable brine.
2. Injection of a slug of "dirty brine" or other thermodynamically unstable brine into selective locations of the reservoir.
3. Mixing of an injection brine which is incompatible with a reservoir brine.

The basis of these methods and their impact on the permeability characteristics of the reservoir are discussed in the report through a precipitation model and through simple flow models. The application of these models are illustrated using Salton Sea brine and Currier 2 brine.

2.0 SUMMARY AND CONCLUSIONS

1. Proper reinjection of the heat depleted brine back into a geothermal reservoir can be an extremely useful way of enhancing the heat recovery from geothermal reservoirs. However, an early breakthrough of the heat-depleted brine poses a great risk to this process.

2. Limited experiences in Japan and other places as reported in the literature show that these injected heat-depleted brines can have an early breakthrough at the production wells. This may result in a disastrous effect on the entire geothermal operation.

3. A break-through earlier than anticipated is normally attributable to the highly fractured nature of geothermal reservoirs. These fractures and other high permeability streaks actually act as "short circuits" to the flow of fluids through the reservoir.

4. The partial "filling up" of the fractures and other high permeability streaks with scale by a forced precipitation of salts can aid in improving the situation by delaying the breakthrough of the injected water. Such a process is called selective scaling.

5. Selective scaling may be accomplished by three methods:

   a) The injection of a thermodynamically unstable brine.

   b) The injection of a slug of "dirty brine" or thermodynamically unstable brine into selective locations.

   c) The mixing of the reservoir brine with an incompatible injection brine in selective locations (e.g., if one of the brines contains SO_4^{--} ions and the other Ca^{++} ions in sufficiently large quantities, their mixing would result in $CaSO_4$ precipitation).

6. The calculation of the permeability change due to precipitation in an idealized fracture system showed that a substantial decrease in permeability of the medium can be accomplished. However, the design of such a selective scaling for the purpose of changing the permeability characteristics of the reservoir would require a complete knowledge of the reservoir characteristics (especially the location and extent of the heterogeneities).

7. Prior to the design and execution of any injection operation, a thorough evaluation should be undertaken to determine the reservoir characteristics, particularly, the various characteristics of the fractures and other high permeability streaks.

8. The use of radioactive or chemical tracers can offer valuable aid in studying the reservoir characteristics prior to the design of a full scale injection operation and for a constant reservoir verification at later stages of the ongoing injection operations.

9. The simulation of flow in geothermal reservoirs would require a highly complex three dimensional model coupled with a chemical precipitation model. No such models are presently available to tackle this problem in a realistic fashion.

10. The flow pattern in highly fractured geothermal reservoirs cannot be described by radial streamline models. The flow pattern in these reservoirs is more likely to be linear as opposed to radial flow in a relatively homogeneous reservoir.

11. In any modeling of geothermal operations involving injection and production one should consider the gravity effects imposed by differences in the fluid densities of the brines involved.

3.0 RECOMMENDATIONS

Following are some of the suggestions and recommendations on the present evaluation:

1. Tracer tests and Reservoir Engineering analysis should be used to investigate:

   a) The geothermal reservoir characteristics, such as the characteristics of

      (1) The existing fractures,
      (2) The high permeability streaks and
      (3) The existing directional permeability.

   b) The flow patterns in the reservoir. This means, any communication between reservoir layers and/or encroachment from another water body whether it is a bottom aquifer or a neighboring sea can be detected.

2. On the basis of a constant reservoir verification through the use of tracers, a full scale reinjection process may be considered, not only for disposal purposes but also for enhancing the heat recovery through selective scaling.

3. A three dimensional model coupled with a scale prediction model should be developed and used to determine the optimum injection pattern and a forecast of the corresponding ultimate heat recovery.

4. A brine chemically incompatible with the reservoir brine should be injected into a reservoir containing large fractures to slow down the movement of the injection front through selective scaling.

4.0 INTRODUCTION

Heat energy is, by far, the primary resource in a geothermal reservoir. The fluids in a reservoir can exist in the vapor phase as well as in the liquid phase. Based on the relative amounts of the liquid and vapor phases, the geothermal fields are classified as vapor dominated or liquid dominated. Irrespective of the nature of the geothermal fluid in the reservoir , the majority of the heat is stored in the rock matrix rather than in the fluids (more so in liquid dominated reservoirs). Therefore, one can safely conclude that a primary reservoir depletion will be very inefficient as far as heat extraction is concerned.

The heat depleted brine has to be reinjected whether it is for technical, economical, environmental and/or legal purposes. Currently, the majority of the injection wells are completed either above or below a producing geothermal reservoir. The main reason for that is mainly the controversy around the use of heat depleted brines for secondary recovery purposes. It is unquestionable that early breakthrough of a reinjected brine will have a disastrous effect on a geothermal field. On the other hand, primary depletion alone will only lead to a poor heat recovery unless the producing reservoir is naturally recharged.

There are very few reinjection experiences related to geothermal operations. Horne [1], in a recent publication clearly emphasized the complexity of the reservoir engineering aspects of the geothermal reinjection (based on a limited number of studies related to geothermal injection operations in Japan). In many of the examples presented [1], reinjected water seemed to have moved very fast through the reservoir fractures or fissures of extremely high permeability and reached the production wells at early stages of the field life. This may result in a disastrous effect on the entire geothermal operation. In spite of the evident drawbacks presented by Horne [1], it is rather obvious that methods should be developed to enhance the heat recovery from a geothermal reservoir. Reinjection of a heat depleted brine would be one of these methods and could be an extremely useful way of enhancing heat recovery from a reservoir if early breakthrough of the heat depleted brine can be avoided. One possible way of avoiding the early breakthrough of the reinjected brine is by partially "filling up" fractures or other high permeability streaks in the reservoir by the selective precipitation of salts. The precipitation of salts in these regions can be accomplished by means of mixing incompatible waters within the reservoir [2,11], or by injecting a brine which is thermodynamically unstable under reservoir conditions.

5.0 OBJECTIVES OF THE REPORT

The main objective of this report is to investigate the feasibility of enhancing the heat recovery from a geothermal reservoir through selective scaling, within the high permeability streaks, during injection or reinjection of brines. The general ideas presented in this report are highly conceptual in nature, however, they are based on sound basic scientific principles.

The report addresses the following subjects:

1. The lifetime of a geothermal reservoir through primary production alone.
2. The effect of a doublet configuration of injector/producer combination on the lifetime of a reservoir.
3. The dangers of an early breakthrough of injected fluids on the lifetime of a reservoir.
4. Various methods of overcoming the early breakthrough of injected fluids.
5. Feasibility of selective scaling through incompatible water mixing in the reservoir as a means of extending the lifetime of a geothermal reservoir.
6. Feasibility of selective scaling through injection of a brine which is thermodynamically unstable under reservoir conditions.
7. Essential elements needed to accomplish selective scaling for specific situations.

6.0 PRIMARY PRODUCTION FROM A GEOTHERMAL RESERVOIR

Heat mining from a geothermal reservoir by primary depletion alone, will result in a poor heat recovery efficiency. This statement is generally well accepted. One of the main reasons of a poor primary recovery is due to the fact that most of the heat energy is stored in the rock matrix rather than in the fluids. The extreme variety of geothermal reservoir types around the world makes it very difficult to generalize even the simplest concept such as the one we are concerned with here i.e. primary depletion. In hydrocarbon reservoirs, the driving mechanism is the main characterizing factor of the primary recovery process. In geothermal reservoirs, however, the process is complicated by the fact that fluids are merely the carrier of the energy sought. This complexity is also created by the following facts:

The high rates of withdrawal, which are necessary for almost any viable geothermal process, will result in a relatively rapid brine encroachment either from the underburden, overburden or from the sides of the reservoir (e.g., from the sea). The impact of underburden encroachment might be beneficial if the fluids entering the geothermal reservoir are of equal or of higher temperature. On the other hand, a sea water encroachment might be detrimental.

So far, we mentioned the case of a geothermal reservoir connected to other fluid bodies. In the case of a volumetric or closed reservoir, the immediate effect of a high withdrawal rate could be the resulting subsidence effect and a rather quick depletion of the energy that is recoverable by a primary reservoir depletion mechanism. In fact, in the absence of any reflux, the lifetime of such a reservoir would be extremely short.

7.0 IMPROVING RECOVERY THROUGH REINJECTION

Heat depleted brine reinjection is the most obvious way to enhance heat recovery. It is the most obvious way for many reasons:

1. Heat depleted brine has to be reinjected anyway, whether it is for environmental and/or legal purposes.
2. In the case of a closed reservoir, reinjection of the "spent" brine would be an efficient way to avoid subsidence.
3. An optimum injection pattern, coupled with selective scaling in the main flow conduits, could result in an increase in the heat mining efficiency.
4. In the case of a conductive heat encroachment from the underburden, the convective downward movement of the "spent" brine will result in a better sweep efficiency and hence a better heat recovery.

7.1 PRELIMINARY STUDIES PRIOR TO REINJECTION

There are several problems which can develop as a result of the reinjection of a heat depleted brine. These problems can develop in the wellbore as well as in the reservoir regions. The problems occuring in the wellbore are localized in nature. On the other hand, those occuring in the reservoir can affect the whole reservoir life-cycle. The problems associated with the reservoir develop as a consequence of inappropriate or ill-conceived injection design features in locating and operating the injectors. An optimum heat depleted brine reinjection process involves a judicious balance between:

a) The heat removal in the power plant.

b) The cooling of the reservoir by cold brine reinjection.

c) The pressure maintenance of the geothermal reservoir by fluid injection.

Prior to any full scale heat depleted brine reinjection, the reservoir characteristics should be determined. Some of the most important parameters to be considered include the following:

1. The characteristics of the existing fractures in the reservoir.
2. The characteristics of high permeability streaks.
3. Directional permeability.

In addition, a knowledge of the flow pattern, for a given reservoir is a prerequisite for the determination of an optimum injection pattern and the location of future wells.

7.2 TRACER TEST

Any existing reservoir problems far away from the injection and/or production wellbore, cannot be evaluated in sufficient detail using conventional reservoir engineering techniques (e.g., rate and pressure transient testing). Tracers [3 through 6], on the other hand, are ideally suited for investigating the reservoir characteristics at larger distances from the wellbores. Thus, only a combination of rate and pressure test work with tracer studies will allow a study and verification of the critical reservoir characteristics with sufficient detail.

The basic concept of the tracer technique is to add a conventional (chemical) or radioactive tracer to the injected fluid and then assume that the added tracer follows the same flow pattern as the injected fluid. Determining the concentration of tracer in the produced fluid (elution profiles) will then permit the determination of the following information:

1. Breakthrough time at a given producer and the injector or injectors responsible for it.
2. Flow pattern i.e., location of fractures, high permeability streaks, directional permeability.
3. Encroachment and/or communication between reservoir layers.
4. Phase behavior of the reinjected brines.

If tracers are ideally suited for investigating a reservoir at larger distances from a wellbore their use can equally be important around a wellbore and in the surface installations [3]. Around the wellbore, tracers are injected and back-produced in order to investigate reservoir problems around the wellbore. Here again, an interpretation of the elution profiles will allow conclusions to be drawn regarding a certain number of factors such as "thief zones" and other reservoir heterogeneities closer to the wellbore. In summarizing, it can be stated that the characteristics of the reservoir should be as thoroughly and fully determined as possible using tracer techniques, prior to any full scale injection program.

8.0 ENHANCED RECOVERY THROUGH SELECTIVE SCALING

The extension of breakthrough time of the injection water is accomplished by increasing the pressure gradient in the fractures connecting a given injector to the surrounding producers. The pressure gradient is increased through precipitation. The latter will result from:

a) The thermodynamic instability of the injected brine under reservoir conditions and/or

b) The incompatibility between injected and reservoir brines.

There is a great deal of information, in the literature, about the impact of scale and corrosion on injectability [7 through 12]. Unfortunately, this information is generally limited to the most obvious reasons behind a loss of injectability. These are:

1. Corrosion and scale deposits in the wellbore.
2. Suspended solids in the heat depleted brine which are produced during the energy conversion process.

The detrimental effects occur, generally, in the immediate surroundings of an injector [13]. Selective scaling, if designed properly, should occur deeper inside a reservoir.

8.1 SELECTIVE SCALING CONCEPT

Selective scaling is the process of intentionally precipitating large quantities of chemical compounds at selected locations, such as high permeability streaks or fractures, for the purpose of retarding the flow of injection fluids through these flow channels. Such flow retardation will increase the residence time of the injected fluids in the reservoir by a more suitable "heat sweep" thereby enhancing the heat extraction from the geothermal reservoir. The selective scaling may be accomplished by several different methods. Some of the most important ones include the following:

1. The injection of a thermodynamically unstable brine.
2. Injection of a slug of "dirty brine" or other thermodynamically unstable brine into selective locations of the reservoir.
3. Mixing of an injection brine which is incompatible with a reservoir brine.

The basis of these methods and their impact on the permeability characteristics of the reservoir are discussed in subsequent sections.

8.1.1 INJECTION OF A THERMODYNAMICALLY UNSTABLE BRINE

A brine is considered to be thermodynamically unstable for a given set of thermodynamic conditions (e.g. temperature, pressure) if it contains dissolved species in excess of their thermodynamic solubilities. The occurance of thermodynamic instability of the injection brines with respect to certain salts having retrograde solubilities (e.g., CaSO4, SrSO4, etc.,) when these brines are heated and its impact on the detrimental effects in oilfield and geothermal operations have been discussed in several publications [2,11]. However, it might be mentioned here that the thermodynamically unstable nature of the brines can be utilized to an advantage through proper control of the injection brine and the injection process. The general basis for this assertion can be illustrated by the following example.

In recent reports [2,15], the problems associated with injecting three source waters that are available for the geothermal operations in the Imperial Valley , California are discussed. The three waters (so-called "foreign" waters in the report [2]) are the Salton Sea water, Colorado River water and the ditch water. In the present report, the possible use of Salton Sea water as a candidate water for the purpose of selective scaling in fractures and/or other high permeability streaks is discussed.

8.1.1.1 EFFECT OF PRECIPITATION ON THE FRACTURE PERMEABILITY

Table 1 shows the composition of the Salton Sea water. Figure 1 shows the amount of $CaSO4$ and $SrSO4$ precipitate that can form as the Salton Sea water is heated. From Figure 1, it is evident that a maximum of about 2800 mg of precipitate can be deposited from each liter of the Salton Sea brine. This means that each liter of the brine can "fill up" an approximate volume of 1.12 ml of the pore space (assuming that the precipitate has a density of 2.5 g/ml). In other words, the pore spaces of a high permeability streak or fracture can be reduced, thereby decreasing their permeability by precipitating them. The resulting change in permeability as a function of the amount of precipitate can be calculated if a correct correlation between permeability and porosity is available. For the purpose of illustration, a specific problem of a system of linear fractures in a tight matrix are considered. The various parameters for the problem are shown in Table 2. For permeability/porosity correlation, Muskats` expression (see also Table 2) for the fracture permeability is used. Figures 2 through 5 show the changes in permeability versus the amount of precipitate for various lengths and breadth of fractures.

Figure 2 shows the fracture permeability versus the amount of precipitate in the fracture for various fracture lengths. The fractures are assumed to be in the form of a rectangular parallelepiped with dimensions 0.1 X 600 cm cross sections and various lengths between 100 and 400 meters. The other characteristics of the fracture system are given in Table 2.

From Figure 2 (400 m long fracture) it is evident that the original fracture system has a permeability of 8.35 darcies (permeability corresponding to 0 precipitate in Figure 2). To reduce the value of the permeability by 50% (4.17 darcies) would require 1440 kg of the precipitate. If Salton Sea brine is to be used to generate this precipitate, 514,286 liters of Salton Sea brine is required. This is equivalent to 3,240 Barrels of Salton Sea brine. Thus, in principle the permeability of a fractured system can be reduced through selectively forming a precipitate to "cover" part of the void volume of the major fractures. Of course, the utilization of selective scaling through use of a given unstable brine for a given reservoir would require a complete knowledge of the reservoir characteristics. Once these are available, data similar to Figurs 2 through 5 can be generated in order to design an injection system for the purpose of enhanced heat recovery.

8.1.1.2 EFFECT OF BRINE CHARACTERISTICS ON SELECTIVE SCALING

The calculations of the previous section are repeated in this section for the following four brines:

1. 100% Salton Sea brine
2. A mixture of 90% Salton Sea brine and 10% Currier 2 brine.
3. A mixture of 80% Salton Sea brine and 20% Currier 2 brine.
4. A mixture of 20% Salton Sea brine and 80% Currier 2 brine.

The resulting compositions of the four brines are shown in Table 3. Figures 6 through 9 show the permeability versus amount of injection water for the reservoir containing a fractured system. The specific system considered has fractures with cross section of 0.1 cm width and 600 cm height. The length of the fractures is varied between 100 and 400 meters. The height of the pay zone is assumed to be 500 meters with a distance between the fractures to be 10 meters.

8.1.1.3 EFFECT OF INJECTION RATE ON THE FRACTURE PERMEABILITY

In all the computations of section 8.1.1.1 and 8.1.1.2, it is assumed that the scale formation occurs as soon as the injected brine comes into the pore volume of the fractures. However, this is not the case because of the following factors:

1. The injected brine is initially at a much lower temperature (where the brine is relatively stable) and it would require a finite time to reach the high temperature encountered in the fracture (heat-transfer accompanying fluid flow).
2. Even after the brine reaches the high temperature (where the brine is thermodynamically unstable), the actual scale formation is kinetically controlled (nucleation and growth process).

Inclusion of these kinetic factors into any of the "flow with precipitation model" is extremely complex and is not attempted in this study. However, it might be mentioned here that the injection rate should play an important role.

In the present section, the effect of injection rate on the permeability of an idealized fractured system (same parameters as in Table 2) are calculated as a function of the fracture length for three different injection rates. Figures 10 through 15 give the results of these calculations. The effect of kinetic factors are not considered in generating these figures. However, it might be mentioned here that the effect of kinetics on these graphs would be the shifting of the graphs towards longer distances. In other words, the change in permeability will start deeper inside a fracture.

8.1.2 INJECTION OF A SLUG OF "DIRTY" OR THERMODYNAMICALLY UNSTABLE BRINE INTO SELECTIVE LOCATIONS

As shown in the previous section, continuous injection of an unstable brine can result in a decrease in the fracture permeability near the wellbore region. This may not be suitable from the point of view of injectivity of the injection wells. An alternate procedure would be injecting selectively a "slug" or a finite volume of the unstable brine into major fractures to a precalculated distance from the wellbore and letting it form scale by shut-in. The procedure can be repeated until the desired change in permeability is obtained. This procedure would require a complete knowledge of the characteristics of the reservoir through tracer injection, and reservoir engineering techniques. However, the calculations shown in the previous sections would apply.

8.1.3 MIXING OF INJECTION BRINE WHICH IS INCOMPATIBLE WITH RESERVOIR BRINE

The definition of incompatibility of brines and the effect of mixing incompatible waters on scale formation at various locations in a geothermal operation have been discussed previously [2,15,18]. The scale formation resulting from the mixing of incompatible waters can again be utilized in reducing the permeability of high permeability streaks. However, the problem of mixing of various waters in a reservoir is a complex three dimensional hydrodynamic problem. The effect of precipitation of salts superimposed on the fluid movement in the reservoir is even a more complex problem. For the sake of illustrating the possibility of selective scaling some simplified considerations are taken in the present report. These are discussed further in Sections 8.2 through 8.4.

8.2 FLOW PATTERN

Geothermal reservoirs are generally characterized by an extensive fracture network along with a relatively low matrix permeability. Under these circumstances, the assumption of radial flow cannot realistically apply to geothermal reservoirs in general. This means that a streamline model which has been so helpful in visualizing the location of the interface, or mixing zone, between a displacing and a displaced phases in a hydrocarbon reservoir cannot apply to a geothermal reservoir. The streamline models give a strong visual representation of the mixing zones along the stream tubes connecting an injector to a producer (see Figure 16). Even though this representation can realistically be applicable to hydrocarbon reservoirs it might be completely misleading in the case of a geothermal reservoir. The flow configuration in a geothermal reservoir is more likely to be linear (see Figure 17) and miscible.

8.3 GRAVITY EFFECTS

Another effect that may be important and is often discussed in the literature [1,14] is the gravity effect. The density difference between the reinjected heat depleted brine and the reservoir fluids will lead to what has been termed a negative buoyancy [1]. The reinjected brine follows a downward convective movement. This has been actually observed at the Geysers [14], where injection at a shallow depth led to a relatively early breakthrough while injection in the same well but at a much deeper depth did not lead to any communication for five (5) years. The negative buoyancy effect will not be as marked, in a liquid dominated reservoir, as it has been shown in the case of the Geysers which is a vapor dominated reservoir. This gravity effect, in a geothermal reservoir, due to the injection of a denser fluid is exactly the opposite to the well known "steam override" effect in steam injection and fire flooding of hydrocarbon reservoirs (see Figure 18). In the latter case the denser fluid is the one which is in the reservoir i.e., it is not the injected fluid. The other major difference between these two gravity effects, which is worth noting here, is that in the case of a hydrocarbon reservoir there is an important heat loss by conduction (even by convection in some cases) mainly to the overburden. In the case of a geothermal reservoir, on the other hand, the colder reinjected brine will gain some heat (by conduction) from the underburden.

8.4 NEED FOR AN INCREASE IN PRESSURE GRADIENT

The flow configuration in a geothermal reservoir is assumed, from hereon, to be linear. At this point, the reasons behind increasing the pressure gradient in a fracture connecting an injector to a producer are explained. The fracture system provides the main conduits for fluid flow. The heat depleted brine being injected will preferably go to the larger fractures (the least resistant path). Along with the negative buoyancy effect mentioned earlier (see Section 8.2) it is clear that the wider the fracture, the longer will be the interface between the colder reinjected brine and the reservoir fluids (see Figure 19). Therefore more mixing at different proportions (injected brine to reservoir fluids) will take place in the wider fracture. The probable miscible characteristic of a brine displacing another brine and the resulting diffusion and dispersion will increase even further the mixing zone. The mixing of these brines, in this mixing region, can generate precipitates ($CaSO_4$, $SrSO_4$, etc.), if the injection brine has the proper chemical incompatibility [2,11] with respect to the reservoir brine. The resulting scales will reduce the porosity as well as the permeability. The effect of the permeability reduction will be an increase in the pressure gradient across the fractures. It should be well understood that this is a very complex process. Besides the heterogeneities, (an injector and a producer can be connected by more than one fracture as well as by several high permeability streaks), the displacement of a geothermal reservoir fluid by a reinjected brine is subject to:

1. Mass transfer considerations.
2. Energy transfer considerations.
3. Chemical reactions between the injected and reservoir brines.

A quantitative interpretation, even for a doublet configuration of one injector and one producer, will require a three dimensional reservoir model coupled with a scale prediction model. However, certain general statements can be made on the effect of precipitation on the pressure gradient across a fracture. A sufficient amount of precipitated solids in a main flow conduit (i.e., the main fracture) can in principle, generate a pressure gradient across this fracture which will result in a partial diversion of the brine to other flow conduits in a less permeable position of the reservoir. This process will continue as the injected brine flows in the reservoir and continuously takes the least resistant path first. The limiting boundaries would be either a breakthrough or an injectivity impairement. A reservoir simulation study (including the factors mentioned above) is probably the only way to design and monitor an optimum reinjection process.

Such a simulation study, even though a worthwhile project for the development of geothermal resources, is a major task and is not a part of the present study. Here, only the implications and feasibility of selective scaling as a means of retarding the rate at which the injection fluid reaches the producer are discussed. For the purpose of illustration, an example is given here.

Let us consider a simple case where an injector communicates with a producer through a high porosity and a high permeability streak. The fluid and reservoir data for the example are given in Table 4. The reinjected brine is assumed to have a temperature of 200° F. The fictitious relative permeability data are given in Figure 20.

Assuming a Buckley-Leverett type displacement the location of the flood front at various times is calculated. Figure 21 shows the injected brine front, after 750 days of injection, at 1959 barrels/day (the other relevant data are given in Table 4). The calculations are repeated for a different injection rate. Figure 22 shows the injected brine front under the same conditions as those outlined in Figure 21 except for the injection rate which is now 1567 barrels/day. This 20% reduction in the injection rate may be felt in two ways:

1. At the wellhead, (that is an injectivity impairment which is not desired) or more likely,

2. In heterogeneities linked to the high permeability streak considered in this example.

Eventhough these heterogeneities are permeables, most of the injected brine will go through the main flow path considered in this example. If the main flow path is somehow restricted the heterogeneities linked to it start taking a larger share of the injected brine which will be "diverted" towards other wells or other areas of the geothermal reservoir, away from the doublet considered in this example. The flow divertion mentioned above is achieved through selective scaling. At the start of the injection, the brine will naturally follow the least resistant path first, which could be either a fracture or a high permeability streak. If the brine in that main path is chemically incompatible with the reservoir fluids, or if it is thermodynamically unstable under reservoir conditions, scale will form. The scale formed will reduce the porosity and hence the permeability of that main flow path up to a point where it is no longer the least resistant flow conduit. At this moment, a portion of the injected fluid will be "diverted" towards other flow conduits, thereby reducing the velocity of the injected brine front which is the closest to the producer. For the example shown in Figures 21 and 22, it should be interesting to find out the amount of scale, required to reduce the porosity and hence the permeability in order to "divert" (away from the cross sectional area considered) 20% of the injected fluid. For the sake of simplicity, let us assume that the permeability to the injected brine is directly proportional to the injection rate and that there is a semi-log correlation between permeability and porosity. Under these assumptions, the amount of scale required to "divert" 20% of the injected brine is shown in Table 5. This table indicates the amount of scale which has to be deposited per liter of injected brine to achieve a permeability reduction of 20%. This deposition is assumed to occur uniformly within a given distance from the wellbore. Table 5 is based on the data and assumptions of the example presented in section 8.3. In other words, a brine with a scaling tendency of 432 mg/liter will achieve a permeability reduction of 20% under the following conditions:

1. 750 days of injection at 1959 barrels/day.
2. The scale is forming uniformly within 1 foot from the wellbore.
3. The injected brine is thermodynamically unstable under reservoir conditions.

If the scale is forming uniformly, within 5 feet from the wellbore instead of 1 foot, the scaling tendency of the injected brine should be 2160 mg/l (see Table 5) to achieve the same permeabililty reduction.

Table 6 shows various permeability reductions with the amount of scale deposited within a specified distance from the wellbore. The data and assumptions for Table 6 are the same as those of Table 5 except for the injection rate and the original permeability. In this case they are: 9583.4 barrels/d and 2 darcies respectively. Up to now we have used a specific example in order to develop some "hard numbers". A general procedure can be outlined to achieve a given permeability reduction and to determine the characteristics of the appropriate brine. As mentioned earlier in this report (section 7.1) the reservoir characteristics should be determined prior to any full scale reinjection process. A first stage will be to determine the breakthrough time and locate the main flow conduit(s) responsible for it. An appropriate reduction of that (these) main flow conduit(s) permeability is estimated. This reduction in permeability should not result in an impairment of the injectivity potential of the well. In order to achieve this permeability reduction, one has to determine the appropriate scaling tendency of the injection brine. The latter is considered to be thermodynamically unstable under reservoir conditions. The scaling tendency will be determined as a function of a specified distance from the wellbore (where the scale is assumed to be uniformly deposited), and as a function of the injection period.

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TABLE 1

CHEMICAL ANALYSIS OF SALTON SEA WATER

CONSTITUENT	CONCENTRATION (mg/l)
Li+	3.2
Na+	10,000
K+	195
Ca++	850
Mg++	1200
Ba++	0.07
Sr++	13.5
Cl-	14,730
SO4--	8100
TDS	40,000

TABLE 2

VARIOUS PARAMETERS AND CORRELATIONS USED TO ILLUSTRATE THE EFFECTS OF SCALING ON FRACTURE PERMEABILITY

I. RESERVOIR PARAMETERS

(1) HEIGHT OF THE PAY ZONE = 500 meters

(2) DISTANCE BETWEEN FRACTURES (S) = 10 meters

(3) NUMBER OF FRACTURES = 50

(4) WIDTH OF EACH FRACTURE (w) = 0.1 cm

(5) BREADTH OF FRACTURES = VARIABLE (100,200,400, 600 cm)

(6) LENGTH OF FRACTURE = VARIABLE (100,200,300, 400 meters)

II. MUSKAT`S FRACTURE PERMEABILITY CORRELATION

TABLE 3

WATER COMPOSITIONS OF VARIOUS MIXTURES OF SALTON SEA AND CURRIER 2 BRINES

CONSTITUENT	SALTON SEA	90% SALTON SEA+10% CURRIER 2	80% SALTON SEA+20% CURRIER 2	20% SALTON SEA+80% CURRIER 2	10% SALTON SEA+10% CURRIER 2	CURRIER 2
Li+	3.2	18.6	34	126.2	141.6	157
Na+	10,000	13,160	16,320	35,280	38,440	41,600
K+	195	924	1654	6,027	6,756	7,485
Ca+	850	2,100	3350	10,850	12,100	13,350
Mg++	1200	1,113	1,026	504	417	330
Ba++	0.07	110.7	221.2	884.8	995.4	1,106
Sr++	1305	14.5	15.4	21.1	22.1	23
Cl-	14,730	24,417	34,104	92,226	101,913	111,600
SO4--	8,100	7290	6,480	1,620	810	<1

TABLE 4

RESERVOIR DATA

Spacing	1000.0 ft.
Cross Sectional Area	99000.0 sq.ft.
Injected Brine Viscosity	.54 Cp.
Reservoir Brine Viscosity	.41 CP.
Reservoir Pressure	6000.0 psi
Reservoir Temperature	300° F
Injection Rate	1959 barrels/day
Reservoir Depth	14000 ft
Permeability	500 md
Porosity =	40%
Irreducible Water Saturation =	16%

TABLE 5

SCALING TENDENCY VERSUS DISTANCE FOR A 20% PERMEABILITY REDUCTION

DISTANCE FROM THE INJECTOR (FT)	SCALING TENDENCY (20% PERMEABILITY REDUCTION) MG/LITER OF PORE VOLUME
10	4320
5	2160
2	864
1	432

Flow Rate: 1959 barrels/day
Initial Permeability: 500 md

TABLE 6

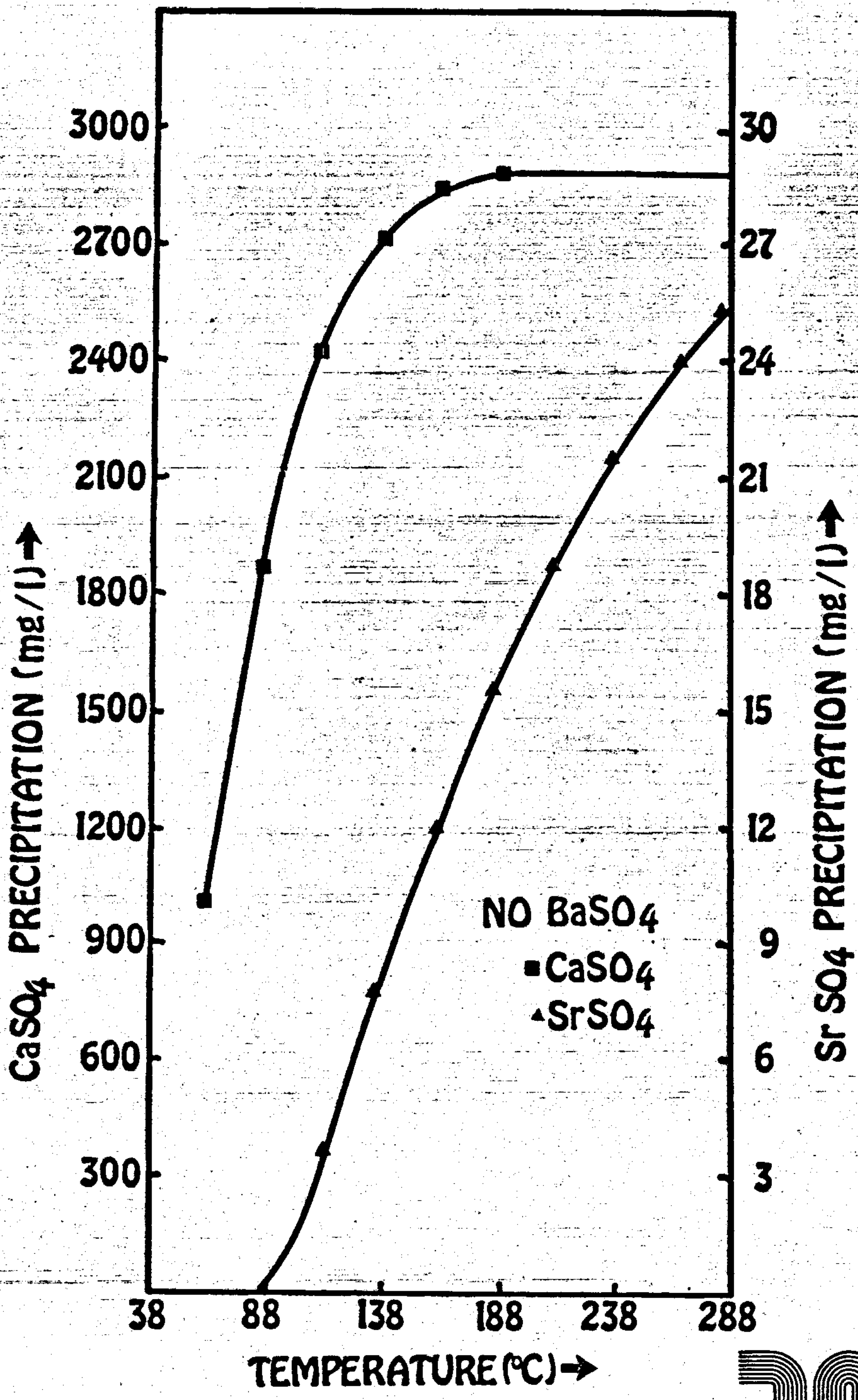
SCALING TENDENCY VERSUS DISTANCE FOR VARIOUS PERMEABILITY REDUCTION

DISTANCE FROM THE INJECTOR (FT)	SCALING TENDENCY FOR VARIOUS PERMEABILITY REDUCTION (IN MG/LITER OF INJECTED BRINE)		
	10%	20%	40%
10	338	717	1656
5	169	359	828
2	68	143	331
1	34	72	166

Flow Rate: 9583.4 barrels/day
Initial Permeability: 2 Darcies

FIGURE 1

PRECIPITATION OF SULFATES UPON HEATING OF SALTON SEA WATER (AT 406 ATM)



FRACTURE PERMEABILITY VERSUS AMOUNT OF PRECIPITATE IN A FRACTURE (0.1 cm WIDE X 600 cm BREADTH)

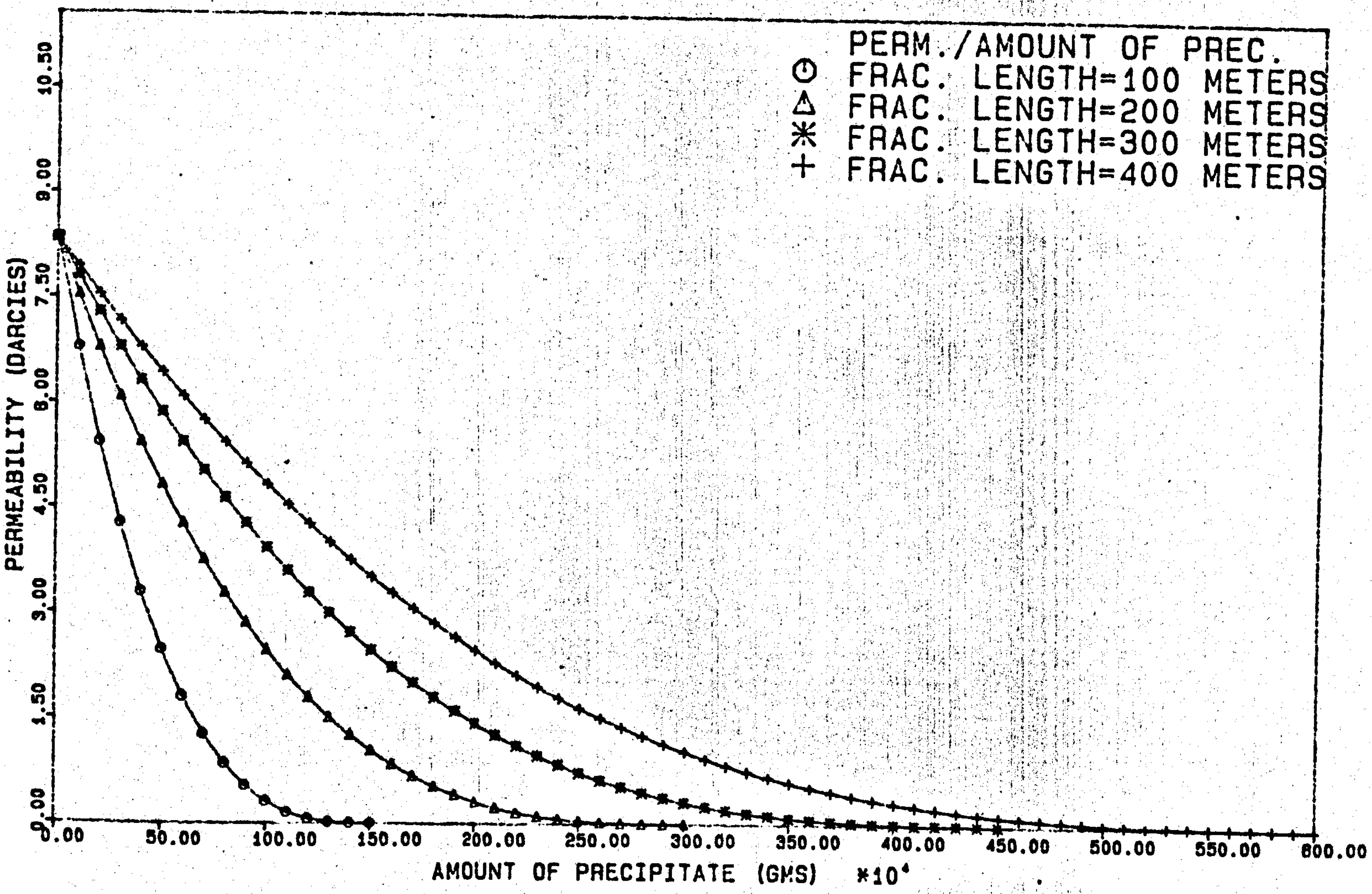


FIGURE 2

FRACTURE PERMEABILITY VERSUS AMOUNT OF PRECIPITATE IN A FRACTURE (0.1 cm WIDE X 400 cm BREADTH)

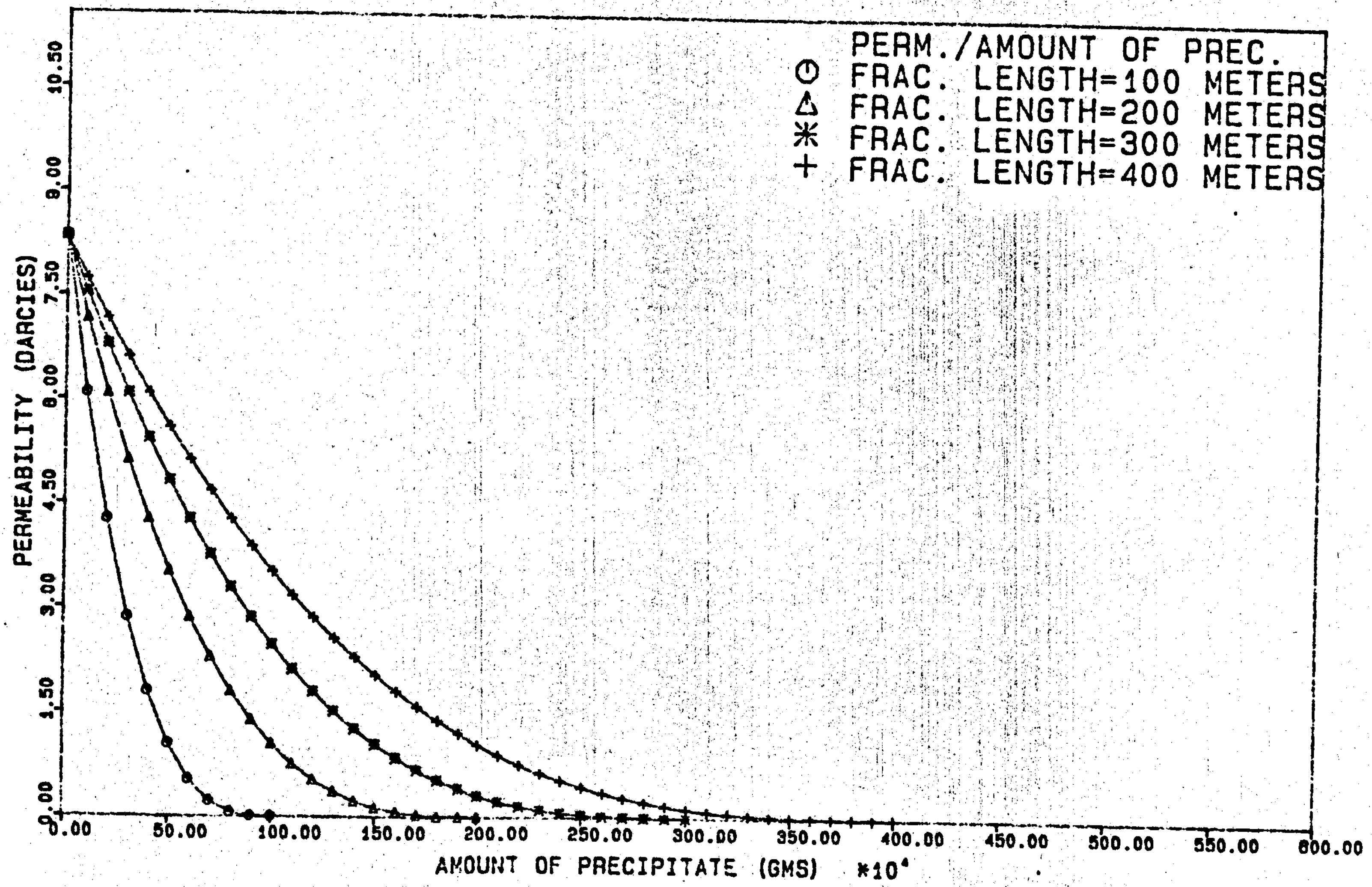


FIGURE 3

FRACTURE PERMEABILITY VERSUS AMOUNT OF PRECIPITATE IN A FRACTURE (0.1 cm WIDE X 200 cm BREADTH)

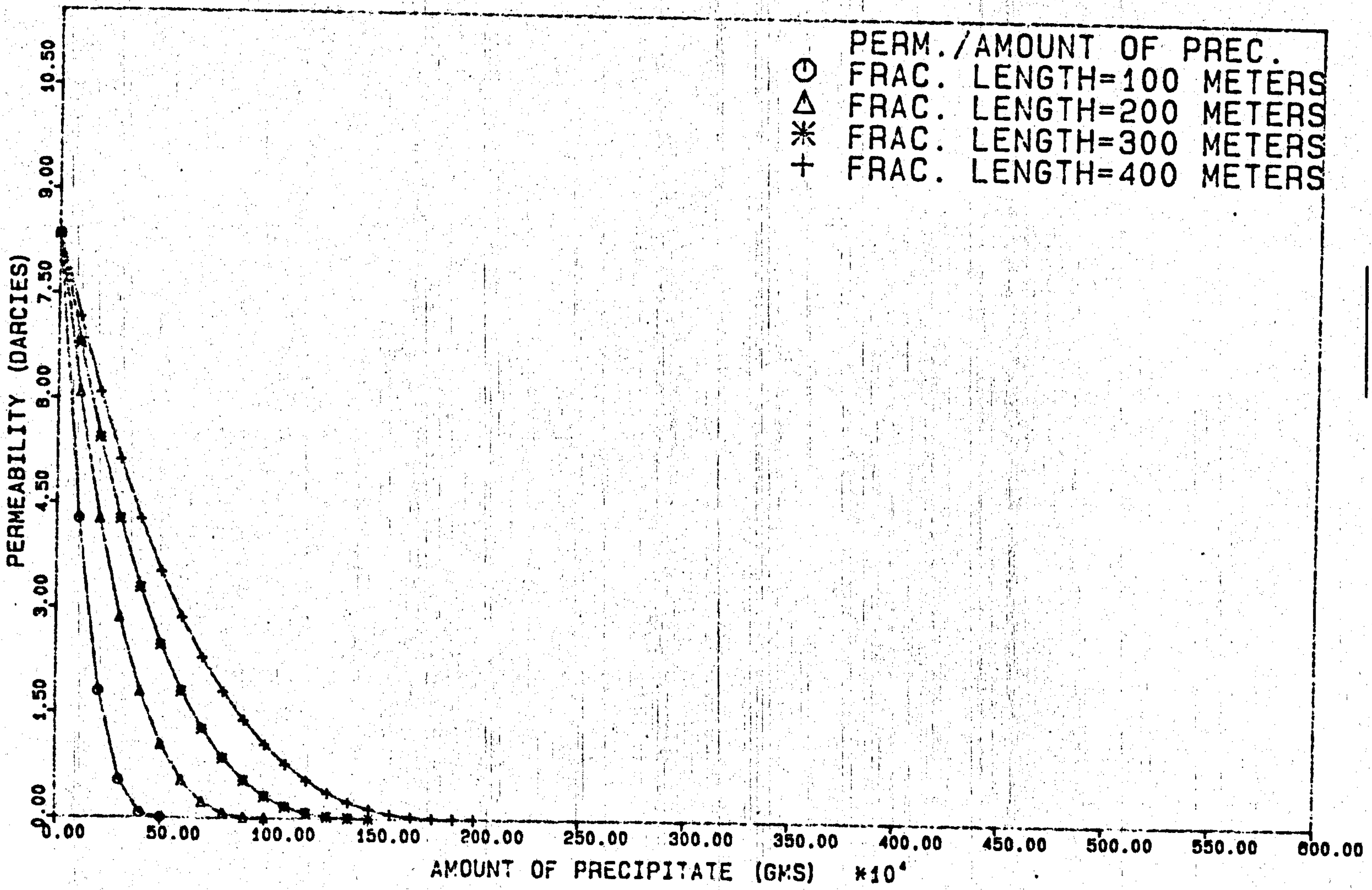


FIGURE 4

FRACTURE PERMEABILITY VERSUS AMOUNT OF PRECIPITATE
IN A FRACTURE (0.1 cm WIDE X 100 cm BREADTH)

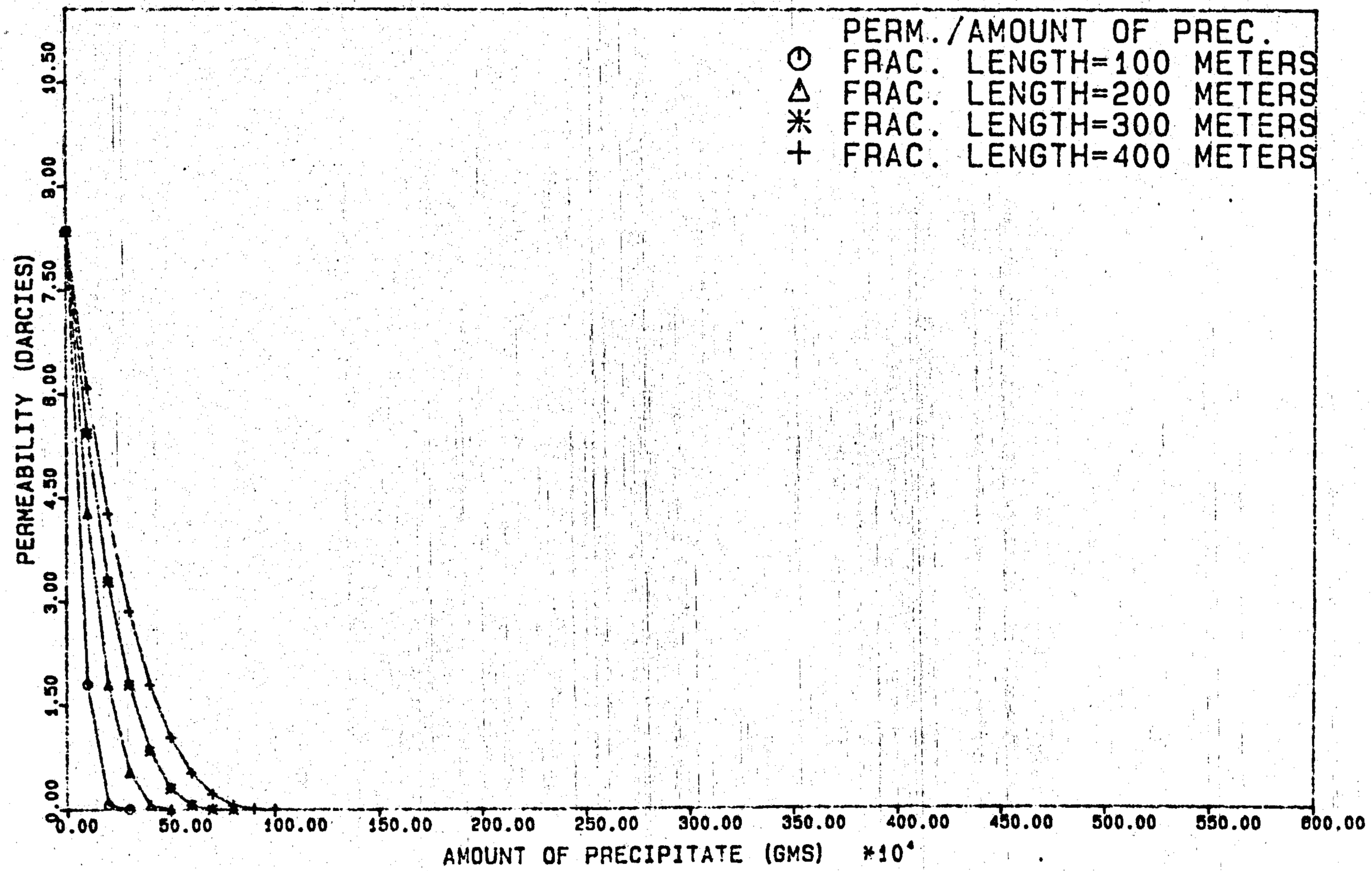


FIGURE 5

FRACTURE PERMEABILITY CHANGE DUE TO PRECIPITATION
VERSUS AMOUNT OF INJECTED WATER
(SALTON SEA BRINE)

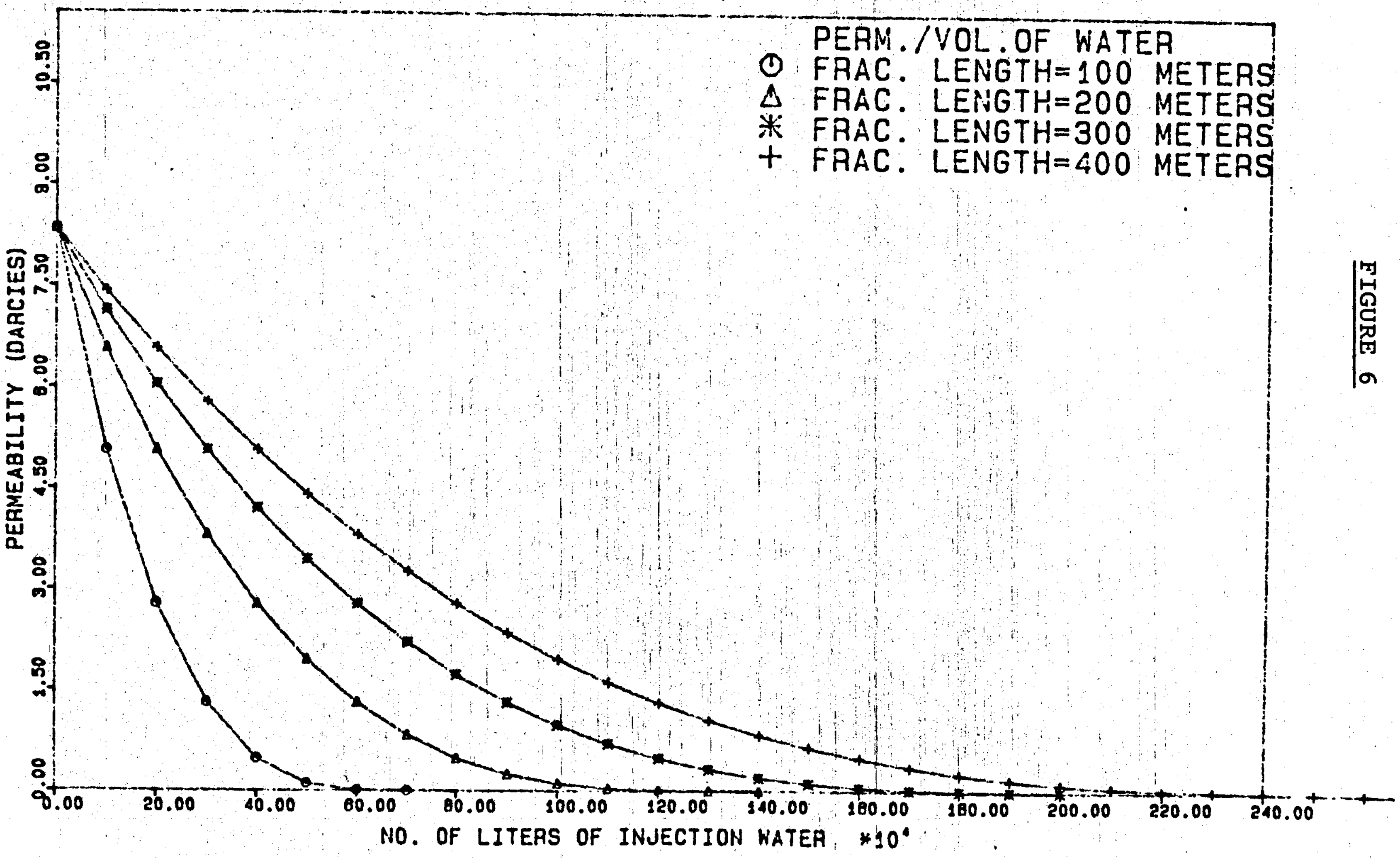


FIGURE 6

FRACTURE PERMEABILITY CHANGE DUE TO PRECIPITATION
VERSUS AMOUNT OF INJECTED WATER
(90% SALTON SEA BRINE + 10% CURRIER 2 BRINE)

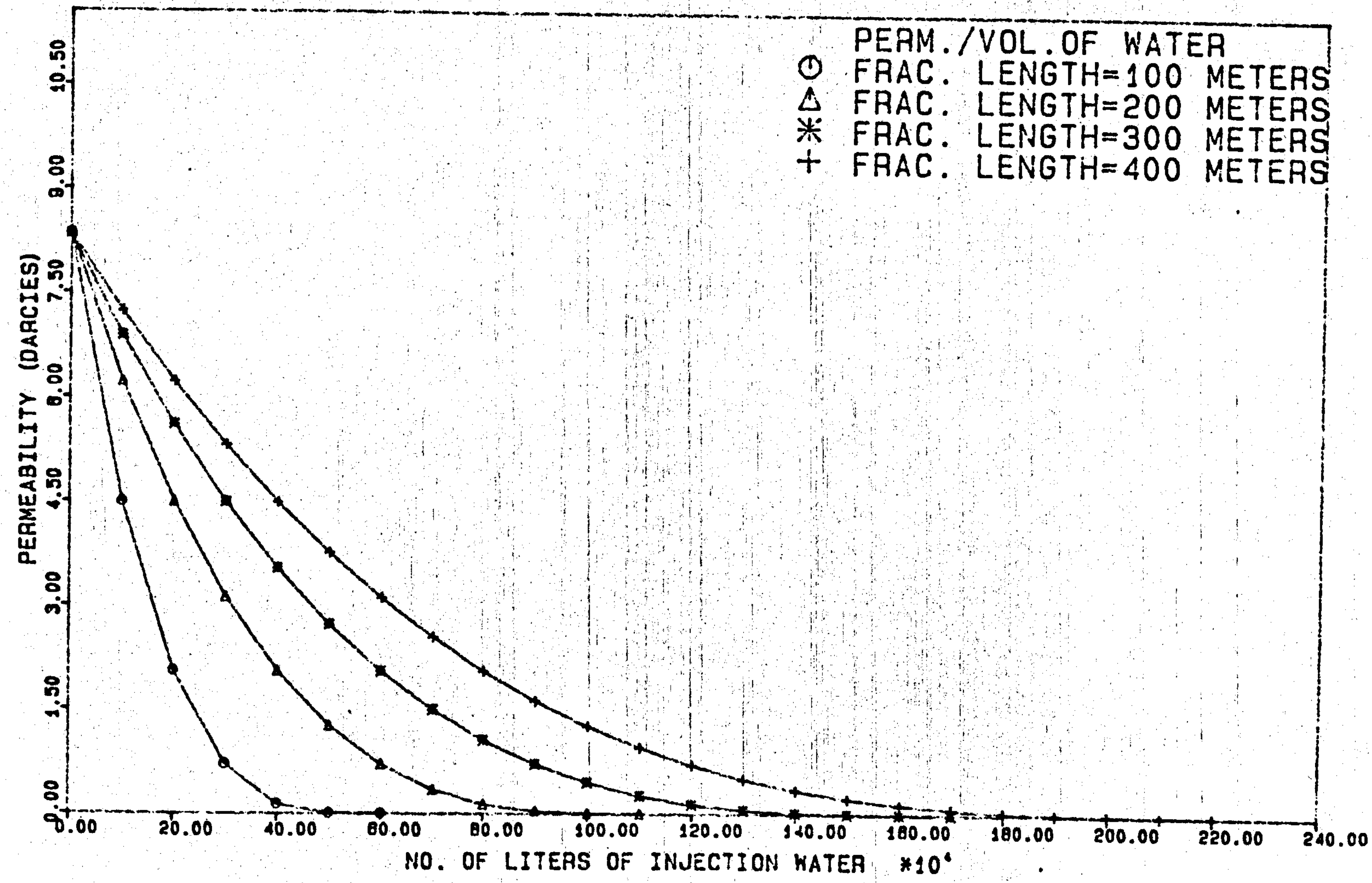


FIGURE 7

FRACTURE PERMEABILITY CHANGE DUE TO PRECIPITATION
VERSUS AMOUNT OF INJECTED WATER
(80% SALTON SEA BRINE + 20% CURRIER 2 BRINE)

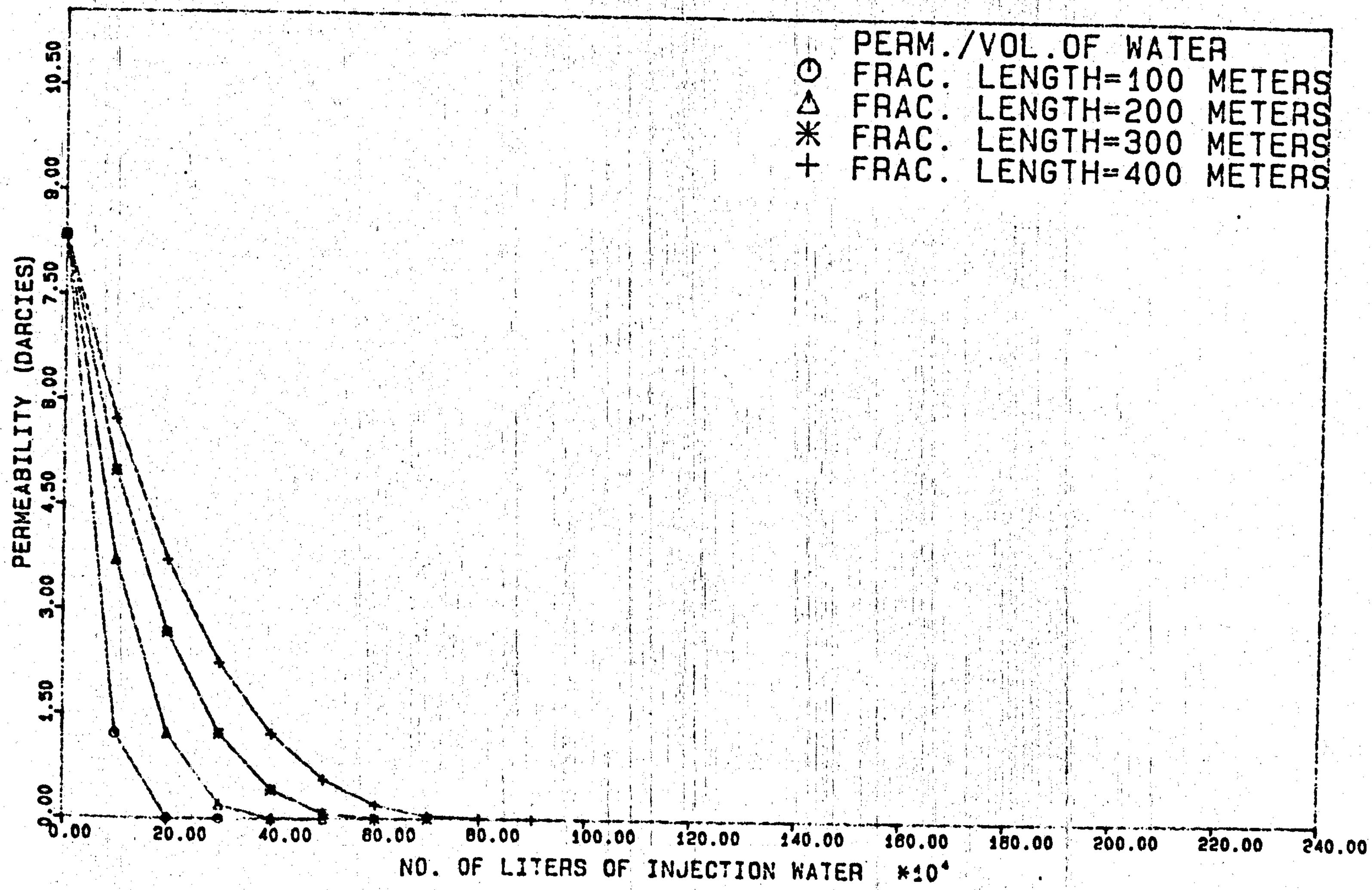


FIGURE 8

FRACTURE PERMEABILITY CHANGE DUE TO PRECIPITATION
VERSUS AMOUNT OF INJECTED WATER
(20% SALTON SEA BRINE + 80% CURRIER 2 BRINE)

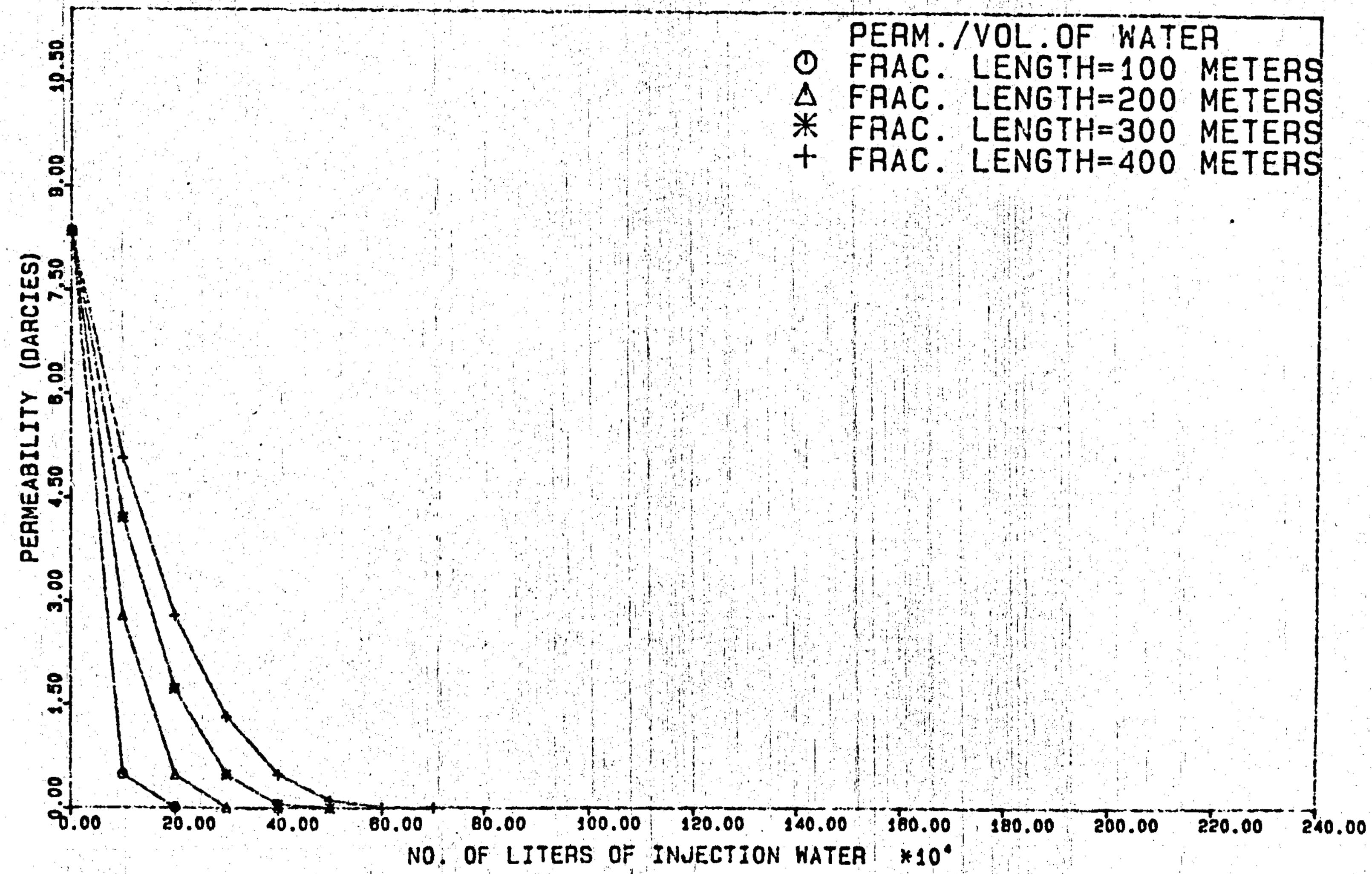


FIGURE 9

PERMEABILITY VARIATION DUE TO PRECIPITATION IN
A FRACTURE FROM SALTON SEA BRINE INJECTION
(FLOW RATE = 50,000 BBL/D)

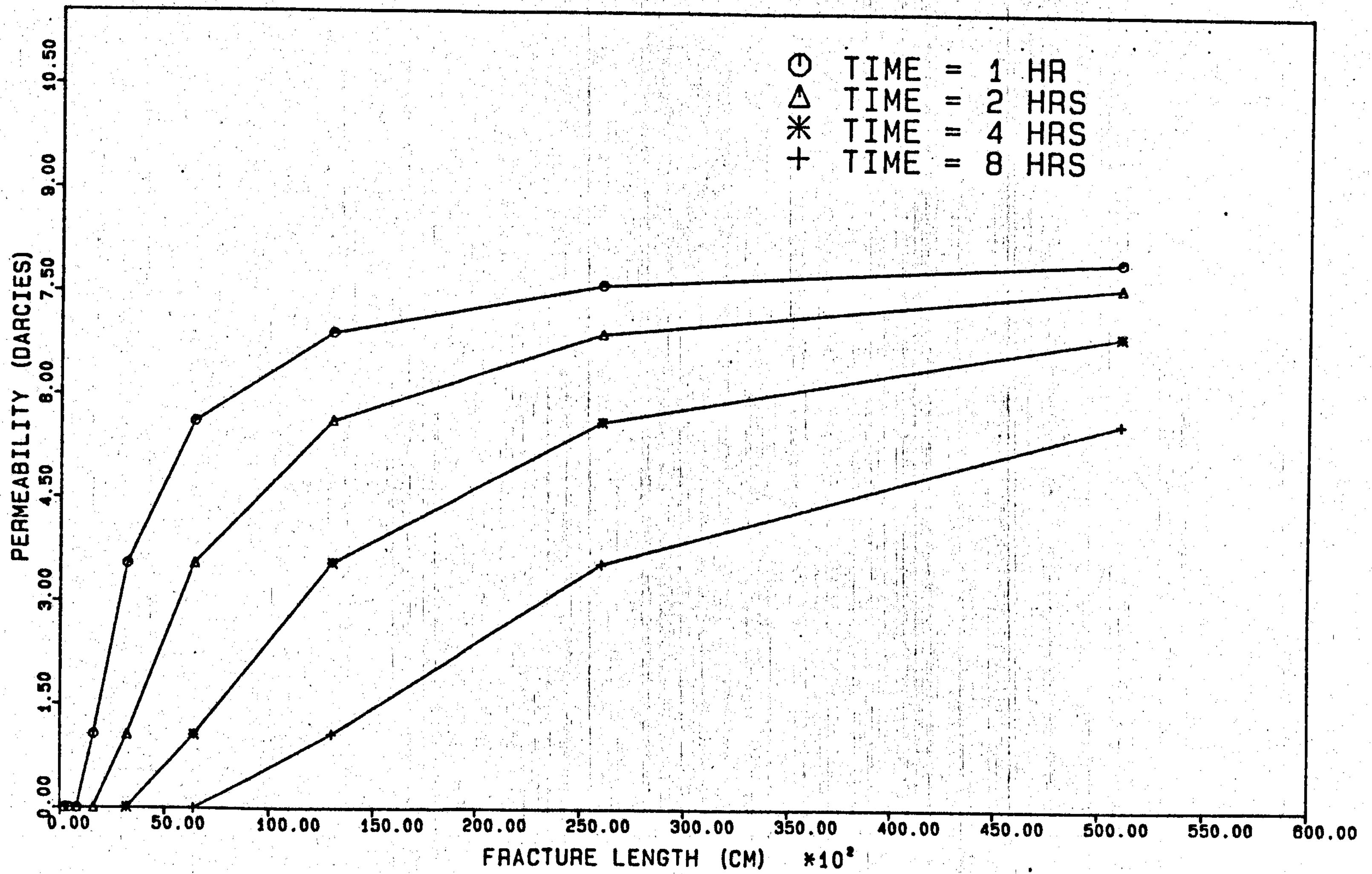


FIGURE 10

PERMEABILITY VARIATION DUE TO PRECIPITATILN IN A FRACTURE FROM SALTON SEA BRINE INJECTION
(FLOW RATE = 5,000 BBL/D)

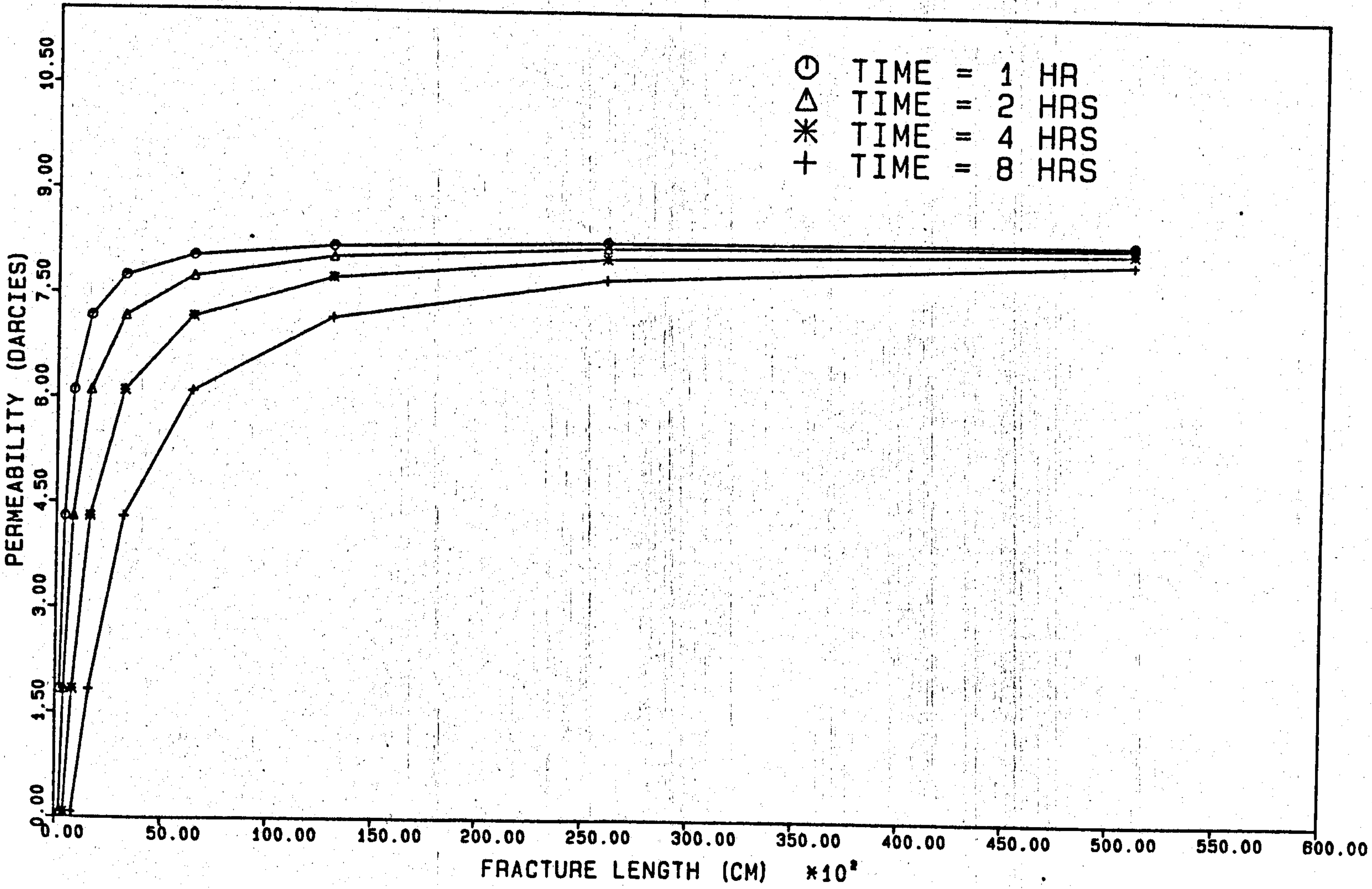


FIGURE 11

PERMEABILITY VARIATION DUE TO PRECIPITATION IN A FRACTURE FROM SALTON SEA BRINE INJECTION
(FLOW RATE = 500 BBL/D)

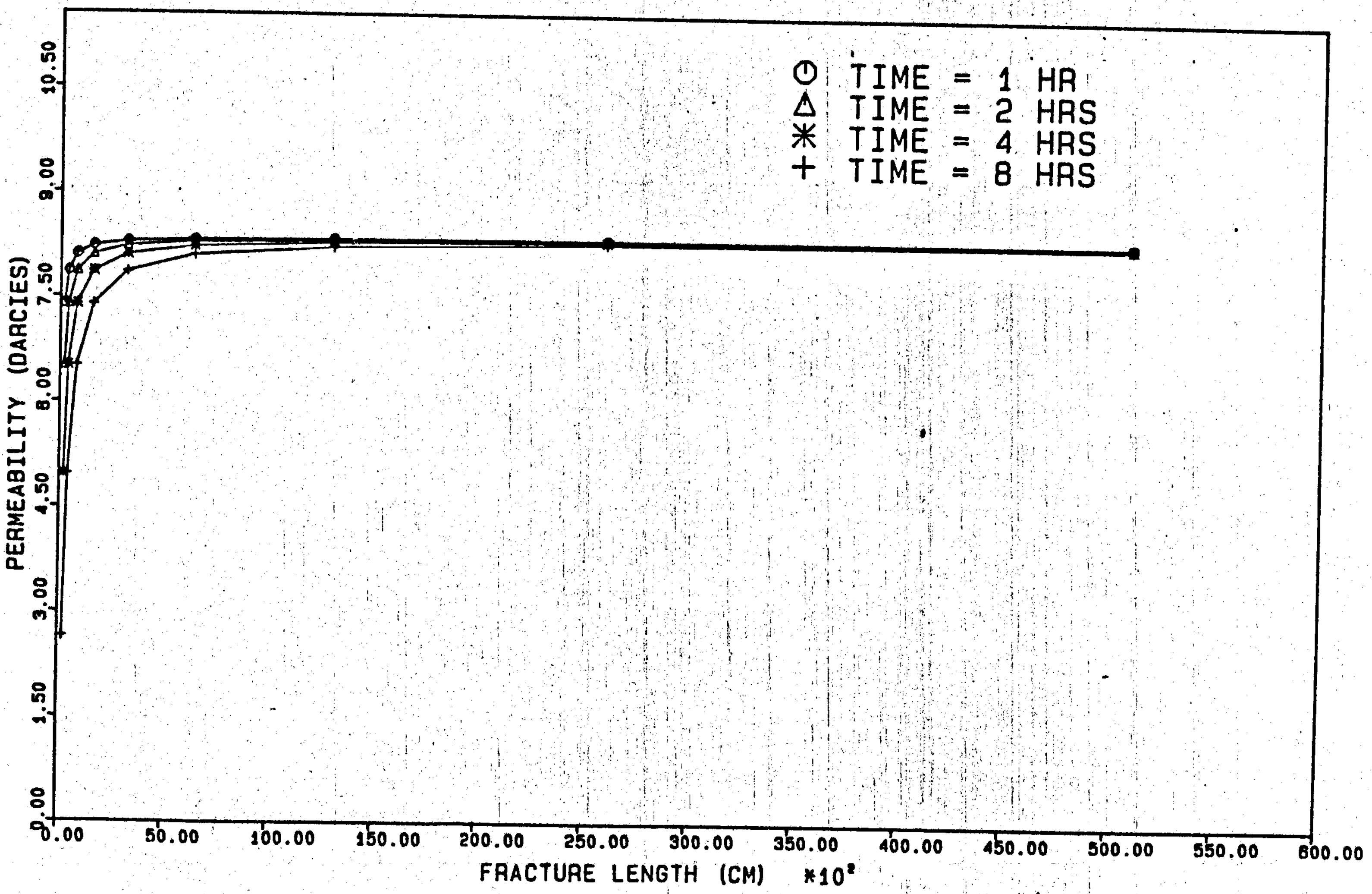


FIGURE 12

PERMEABILITY VARIATION DUE TO PRECIPITATION IN
A FRACTURE FROM SALTON SEA BRINE INJECTION
(FLOW RATE = 50,000 BBL/D)

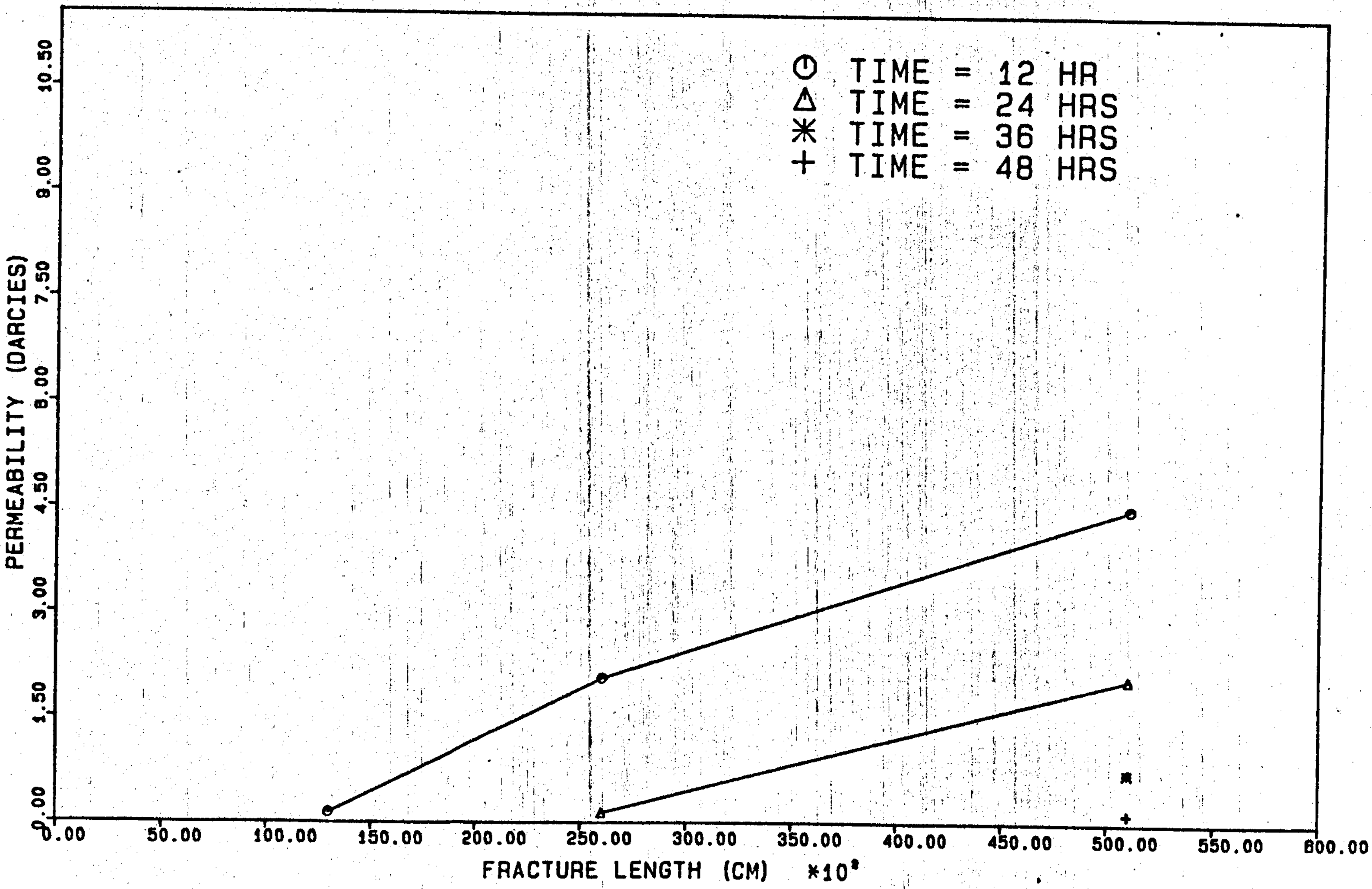


FIGURE 13

PERMEABILITY VARIATION DUE TO PRECIPITATION IN
A FRACTURE FROM SALTON SEA BRINE INJECTION
(FLOW RATE = 5,000 BBL/D)

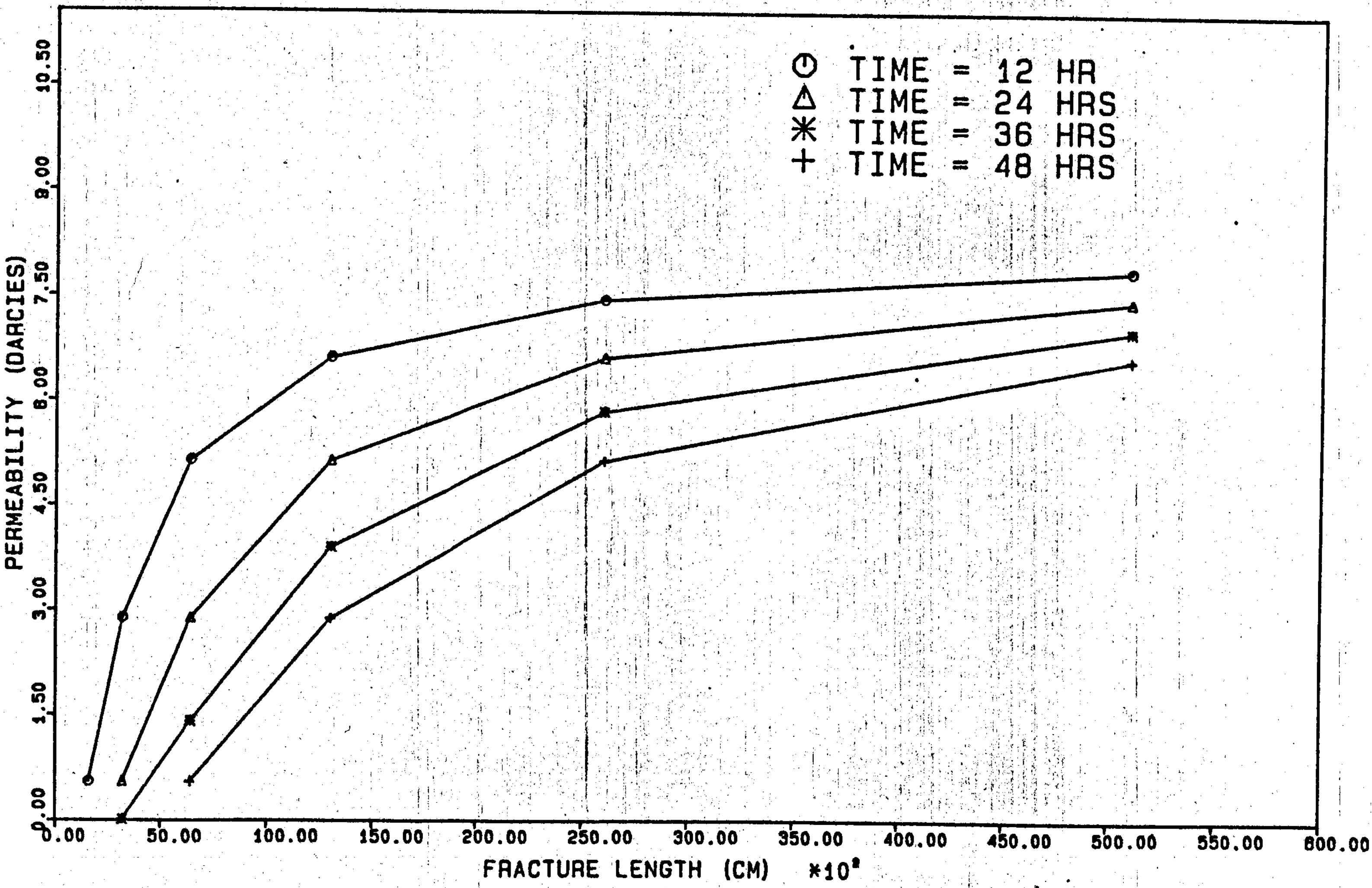


FIGURE 14

PERMEABILITY VARIATION DUE TO PRECIPITATION IN
A FRACTURE FROM SALTON SEA BRINE INJECTION
(FLOW RATE = 500 BBL/D)

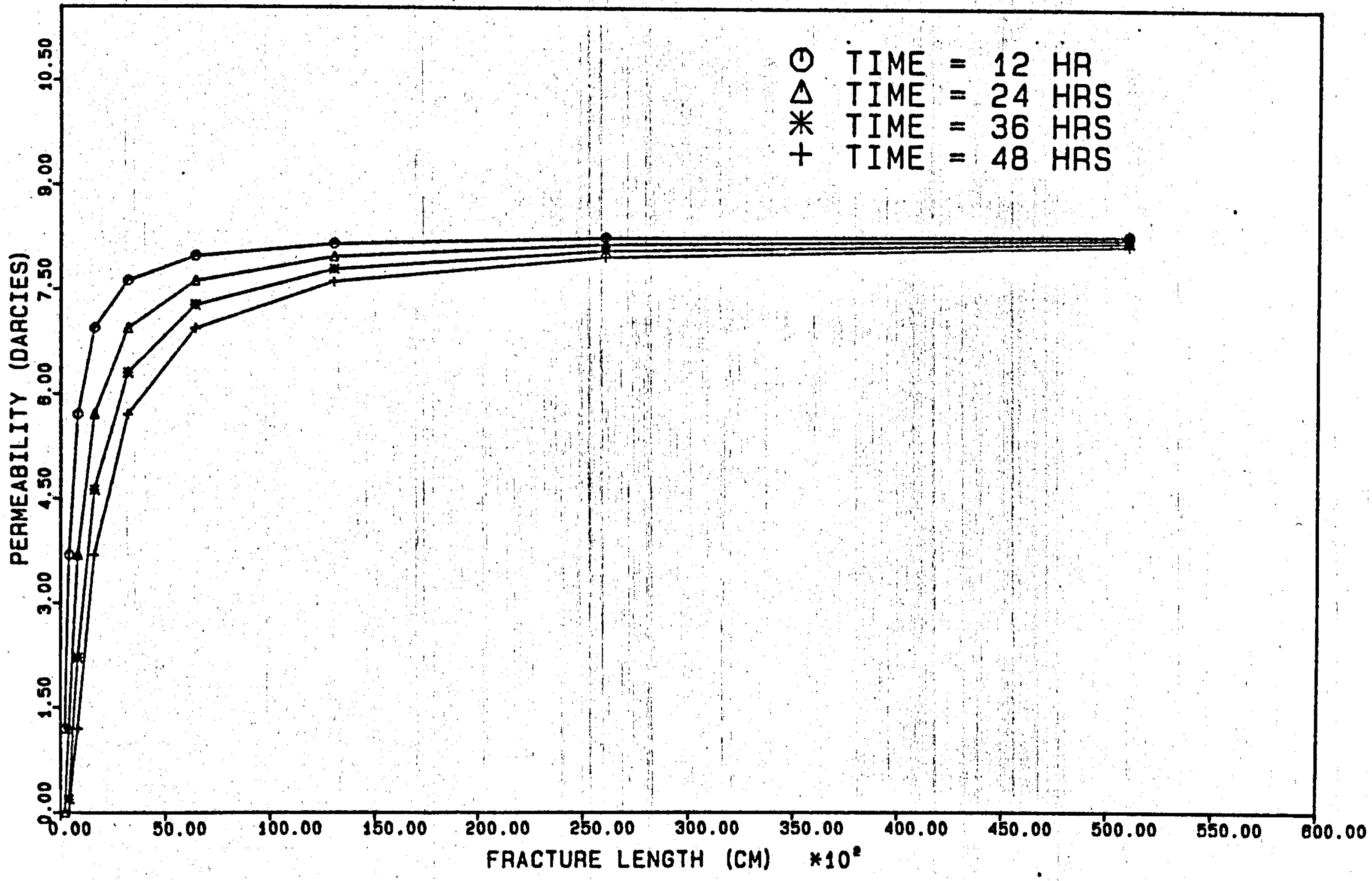


FIGURE 15

MIXING PROBLEMS THROUGH DIFFERENT ARRIVAL TIMES

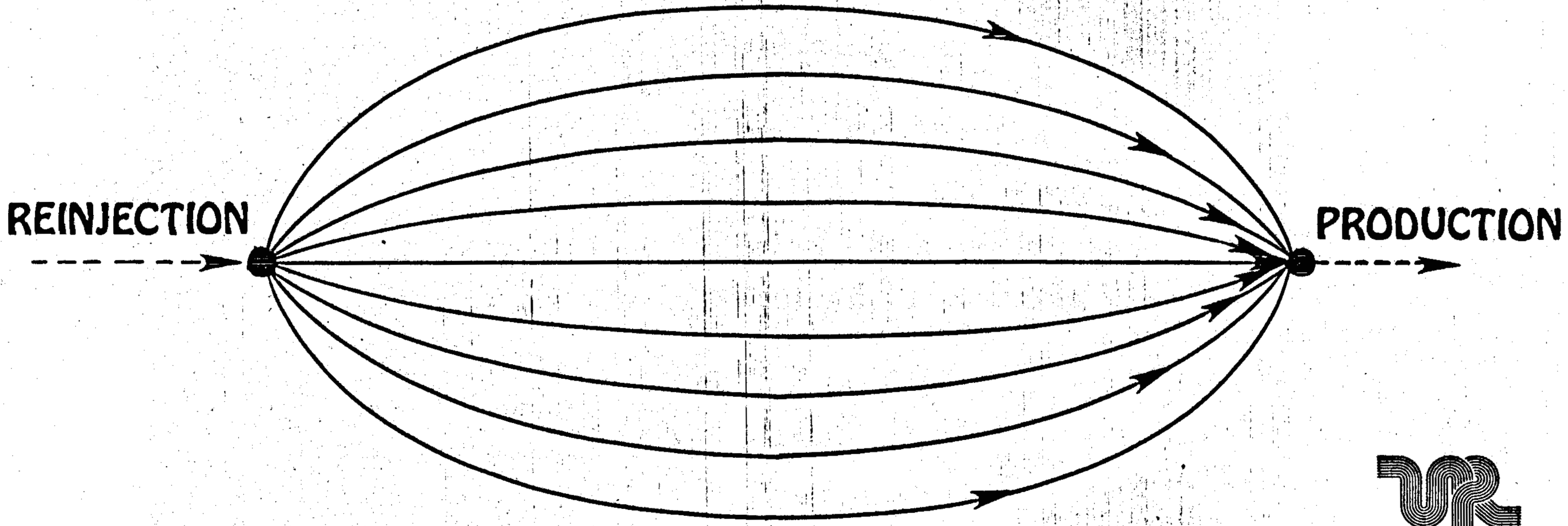


FIGURE 16

SCHEMATIC REPRESENTATION OF A VERTICAL CROSS-SECTION OF A DOUBLET CONNECTED BY LINEAR FRACTURES

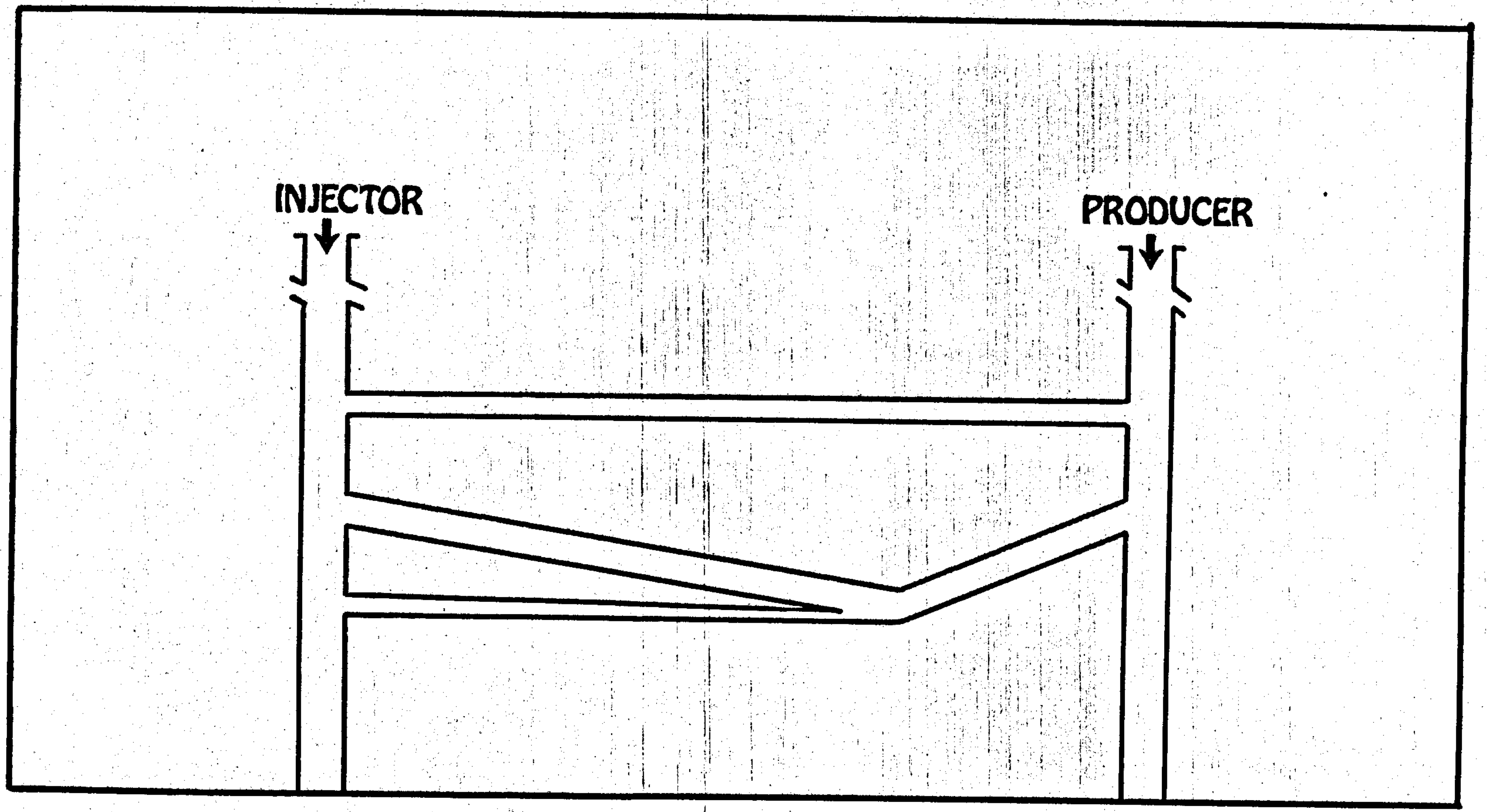


FIGURE 17

SCHEMATIC REPRESENTATION OF
BUOYANCY EFFECT ON FLOOD FRONT

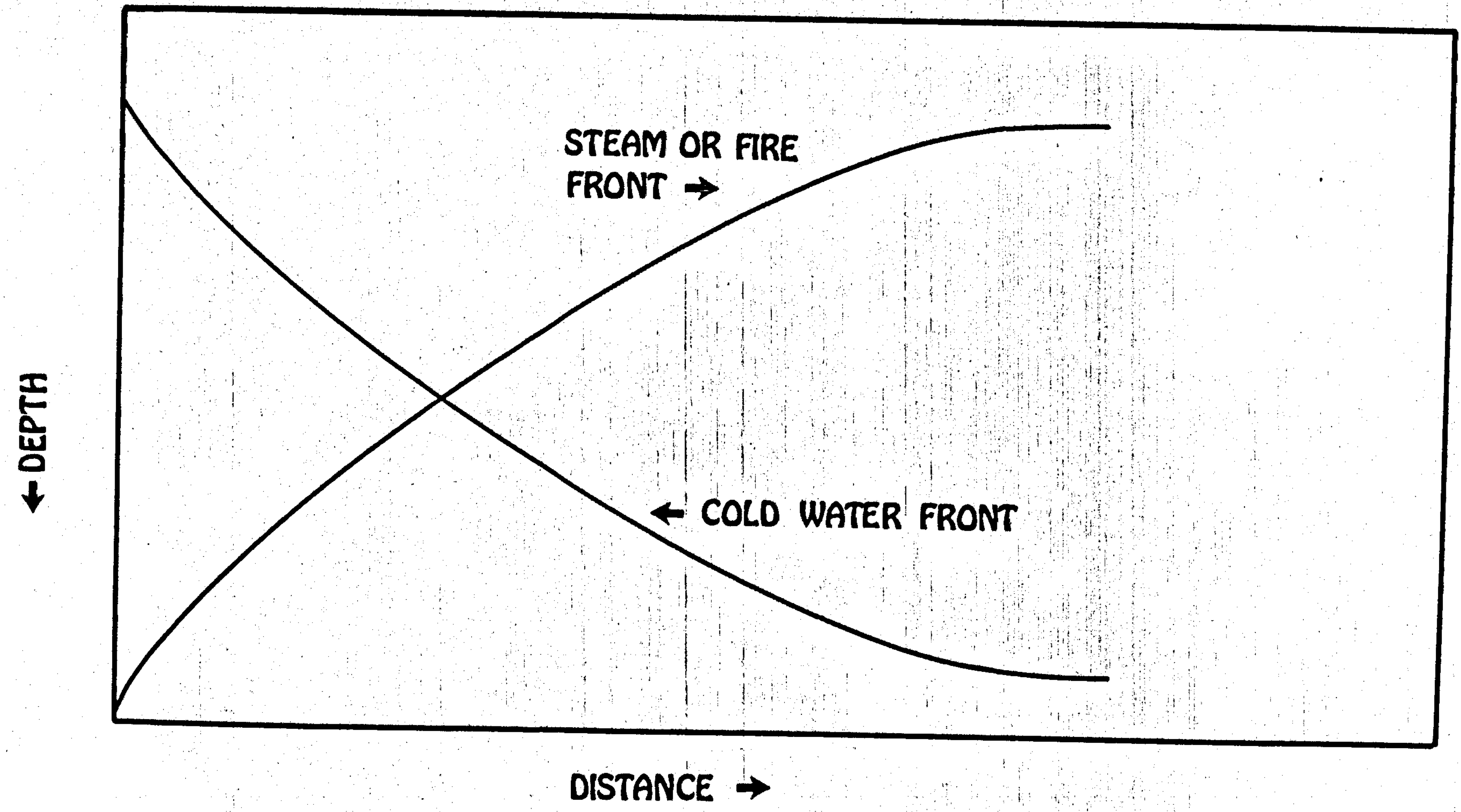


FIGURE 18

SCHEMATIC REPRESENTATION
OF A COLDER WATER FRONT

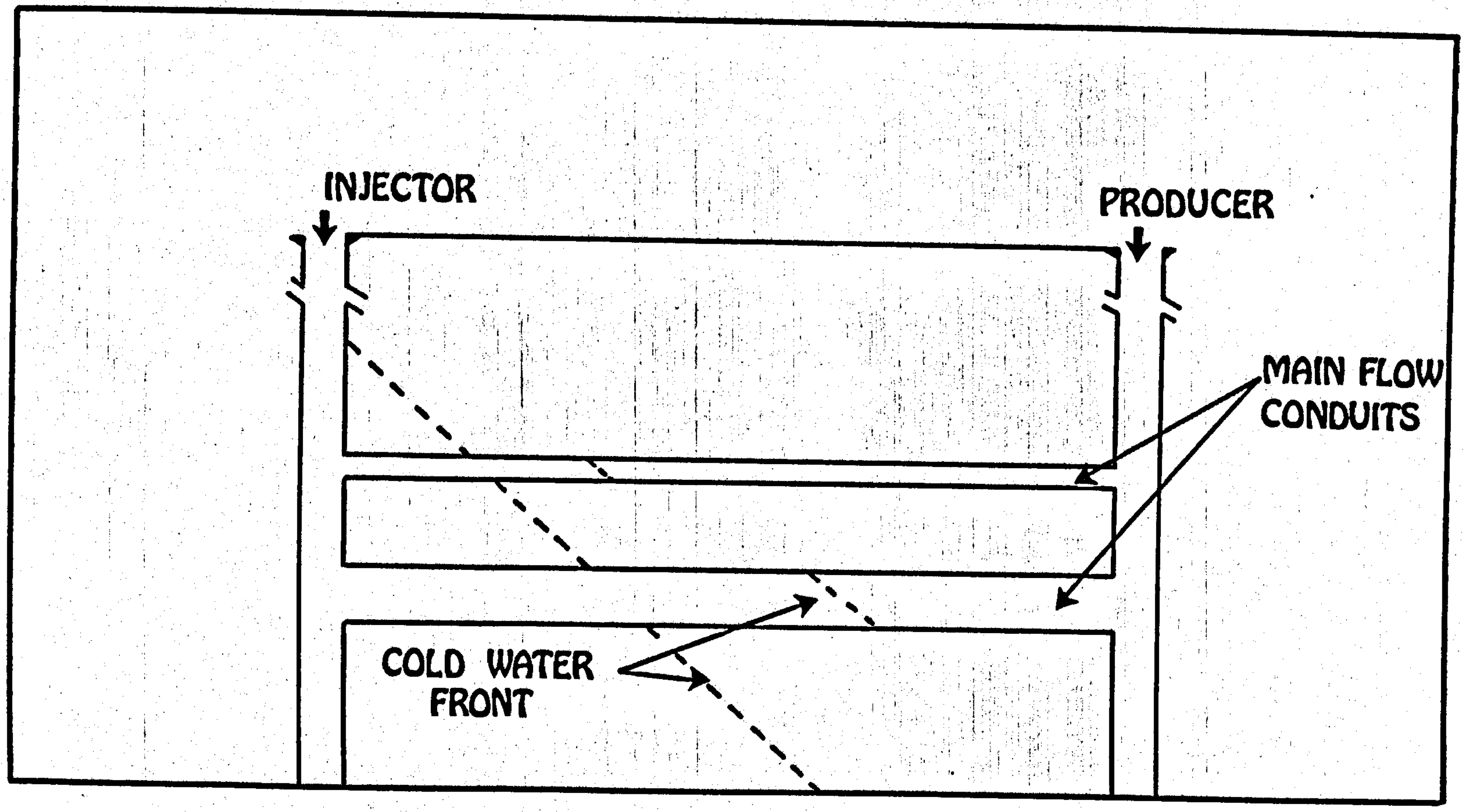


FIGURE 19

RELATIVE PERMEABILITY DATA

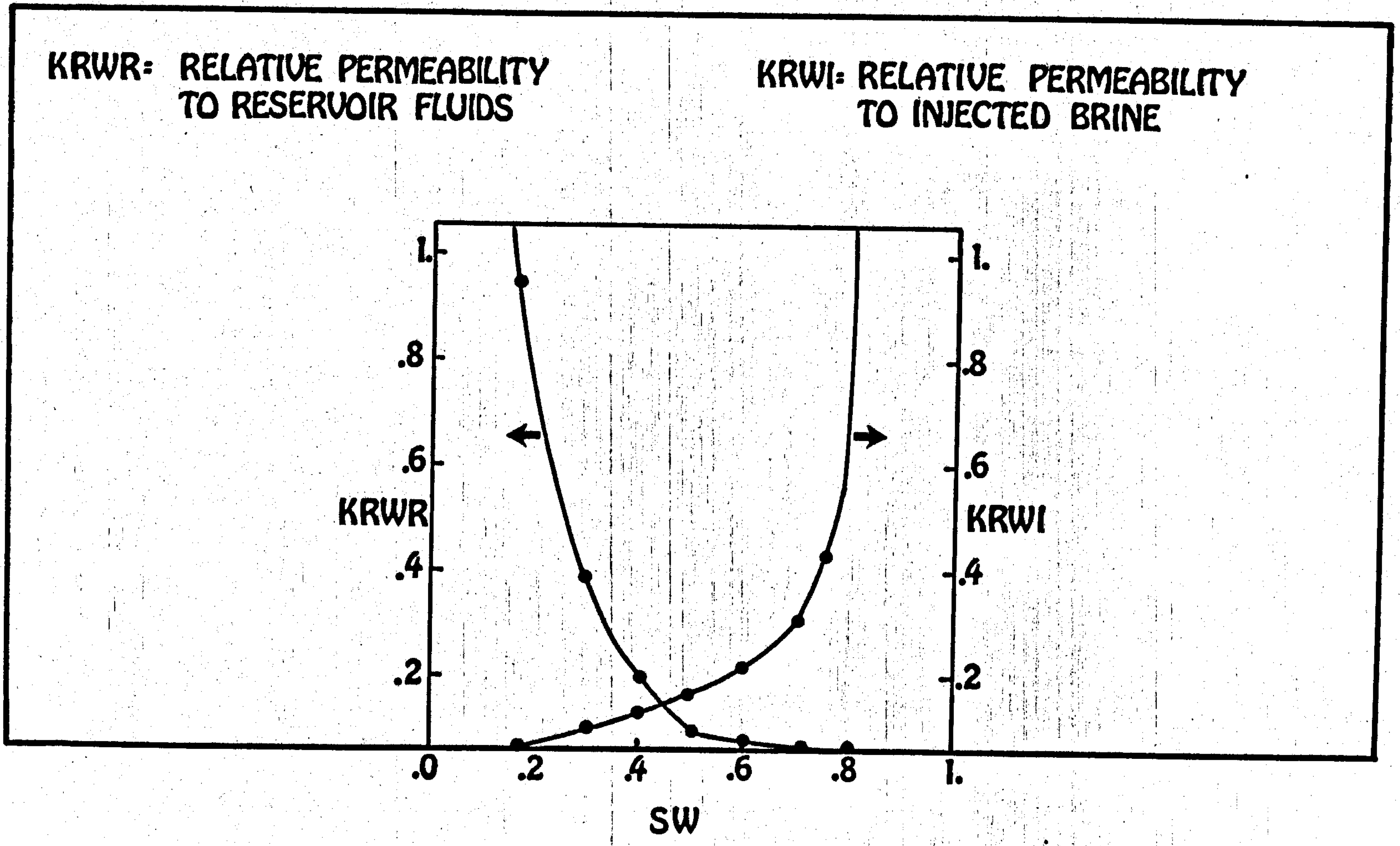


FIGURE 20

INJECTED BRINE FRONT
(AFTER 750 DAYS AT 1959 BARRELS/DAY)

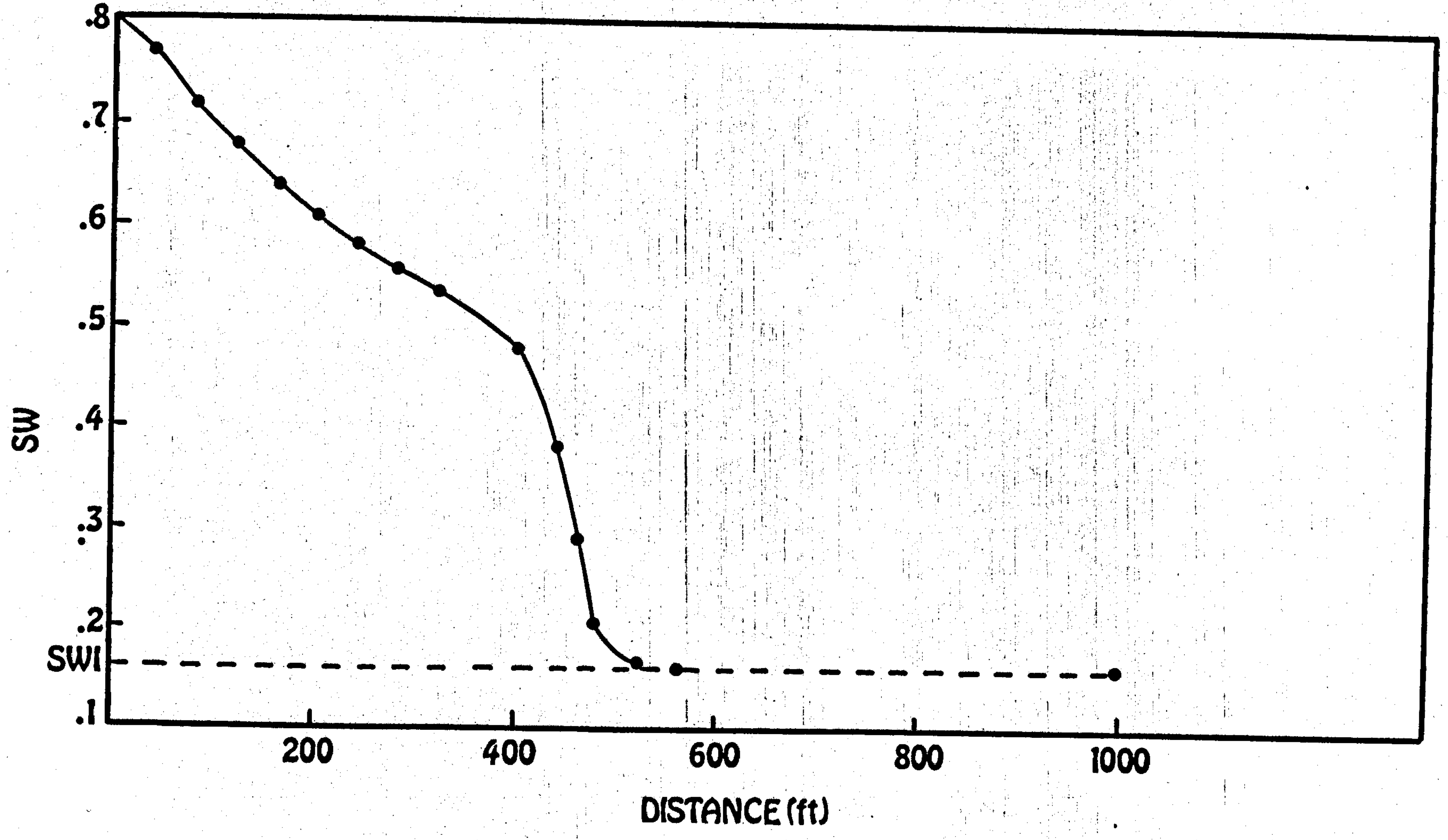


FIGURE 21

INJECTED BRINE FRONT
(AFTER 750 DAYS AT 1567 BARRELS/DAY)

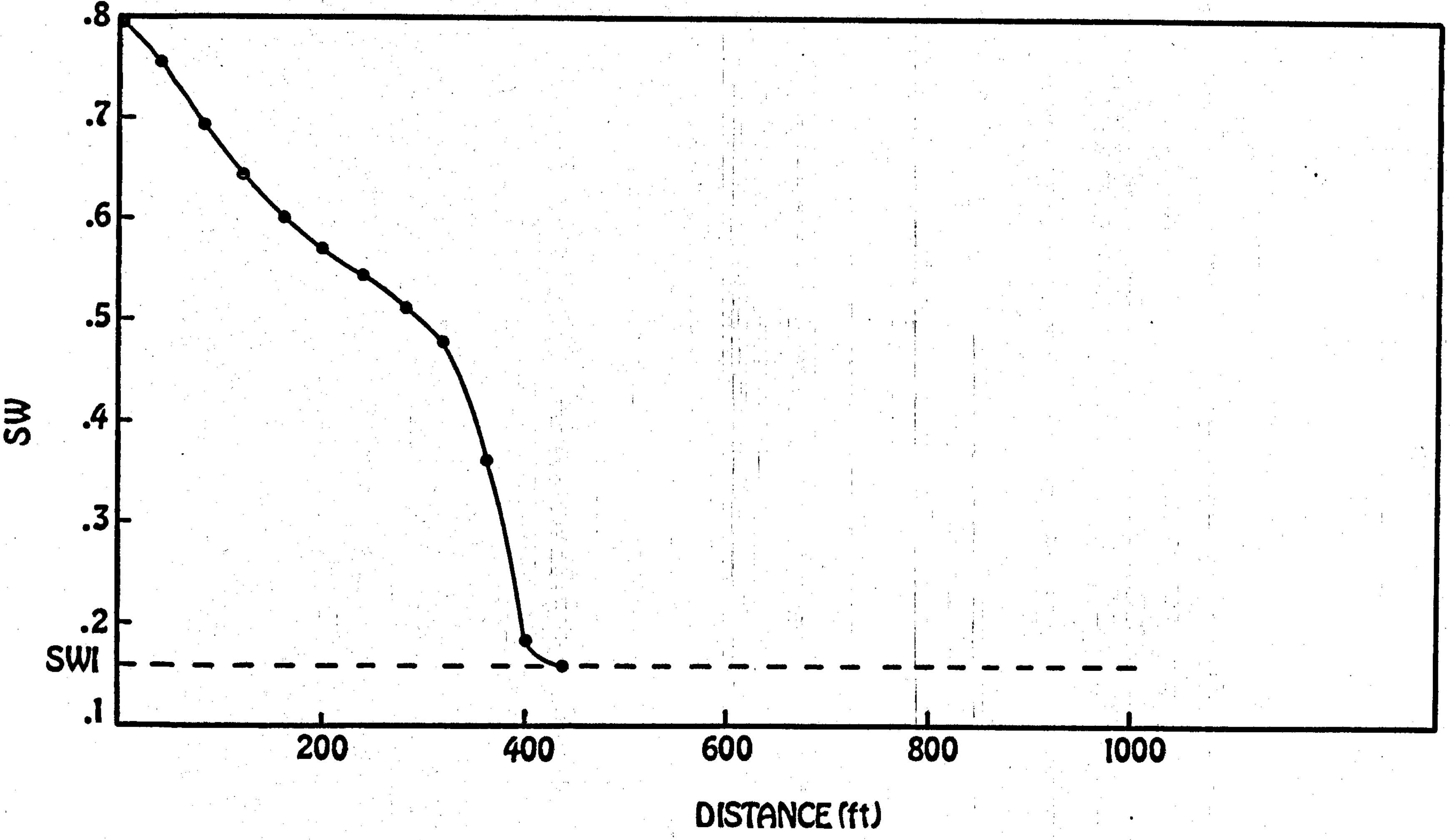


FIGURE 22