

A STUDY OF RELATIVE PERMEABILITY FOR STEAM-WATER FLOW IN POROUS MEDIA

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ABSTRACT

We report on continuing experimental and numerical efforts to obtain steam-water relative permeability functions and to assess effect of heat transfer and phase change. To achieve these, two sets of steady-state flow experiments were conducted: one with nitrogen and water and another with steam and water. During these experiments, a mixture of nitrogen-water (or steam-water) was injected into a Berea sandstone core. At the onset of steady state conditions, three-dimensional saturation distributions were obtained by using a high resolution X-ray computer tomography scanner. By identifying a length of the core over which a flat saturation profile exists and measuring the pressure gradient associated with this length, we calculated relative permeabilities for nitrogen-water flow experiments. The relative permeability relations obtained in this case were in good agreement with those reported by other investigators.

Another attempt was also made to conduct a steam-water flow experiment under adiabatic conditions. This experiment was completed with partial success due to the difficulties encountered during the experiment. The results of this experiment showed that a flat saturation profile actually developed over a substantial length of the core even at a comparatively modest injection rate (6 grams per minute) with low steam quality (4% by mass). The completion of this set of experiments should yield steam-water relative permeability relations in the near future.

INTRODUCTION

Practically all geothermal reservoir engineering problems involving simultaneous flow of steam and water such as well testing and numerical simulations

require use of a form of relative permeability relations. A look at previous geothermal publications reveals that a wide range of analytical and experimental relative permeability relations have been used (Bodvarsson et al, 1980). The analytical relations are normally adopted from experience or from practical considerations while a majority of the experimental relations have been adopted from oil and gas or nitrogen and water flow experiments (Brooks and Corey, 1963; Sorey et al., 1980; Grant, 1980; Grant et al., 1982).

Over the last few decades a number of investigators have reported relative permeability relations obtained from experiments with steam and water. However these results have not been consistent. A number of the studies have reported results similar to those from oil and gas while others have maintained that the two are different (Sanchez and Schecter, 1987; Verma et al., 1985; Clossman and Vinegar, 1988). This state of mixed results has lead to a rather unsettled state of affairs preventing the adoption of these results and no single set of curves to our knowledge has been universally accepted. As a result, these relations have been adopted either from oil and gas or from nitrogen and water for geothermal problems. However, such curves were developed for isothermal processes that do not involve any exchange of materials between the flowing phases and do not involve the heat transfer. Due to these differences, the direct use of these function without any additional consideration may not be proper in geothermal applications. This indeed has been shown to be the case from sensitivity studies of the effects of relative permeability relations on fluid flow from reservoir to wellbore and forecasting long time response of reservoirs to production (Bodvarsson et al, 1980; Reda and Eaton, 1980). It is therefore important to obtain reliable relative permeability relations that are applicable to the flow of steam and water.

This paper presents the results of an experimental investigation of the problem of two-phase steam and water flow using an improved method for measurement of fluid saturation within the core using X-ray computer tomography. In addition, we have measured pressures at various locations along the core in order to determine more precisely the pressure gradients associated with each flowing phase. To demonstrate the effectiveness of these method, relative permeability relations for nitrogen and water, which are comparatively better understood, were obtained from a steady state experiment. These results will be compared to those for steam and water on similar cores to establish the effect of phase change and heat transfer.

REVIEW

The concept of relative permeability is an attempt to extend Darcy's law for single-phase flow of fluid through porous media to account for simultaneous flow of two or more phases. In this regime the flow of each fluid is governed by the microscopic pressure gradient to each phase and the fraction of the overall permeability that is associated with it. This fraction is normally expressed as a fraction of the media's permeability to single phase fluid, normally the wetting phase, and is called the relative permeability. Since being introduced by Buckingham in 1907 and popularized by Hassler and coworkers in 1930's, relative permeabilities have been expressed as a function of saturation principally because it was thought that they depend on the volume fraction of the pore space occupied by each phase. Whereas a great number of experiments have shown this to be true, a number of investigators have shown that relative permeability depends on several other parameters e.g. interfacial tension between the phases, viscosity ratio of the fluids and wetting characteristics (Fulcher et al, 1983; Osoba et al, 1952). Since these parameters change with the type of fluid it should be expected that relative permeabilities will show variation with fluid type for a given porous material.

As discussed by Heiba et al (1983), experiments are the only reliable method by which relative permeability can be determined. However, laboratory techniques suffer from limitations imposed by boundary effects caused by capillary forces. Capillarity does introduce nonlinear effects on pressure and on saturation distribution of the wetting phase at the core exit. Thus, experiments must be designed carefully to eliminate these effects. Osoba et

al (1952) have given a summary of the methods used to obtain relative permeability for two component systems that to a large extent eliminate these effects and have been used successfully in problems of oil and gas. However, all of these methods are for experiments conducted under isothermal conditions without phase change. In two-phase flow it is impossible to maintain such conditions as pressure drop across the core is accompanied by temperature change and would inevitably lead to phase change. This in turn will result in a changing saturation distribution across the core which would lead to a nonlinear pressure gradient across the core. These two factors have been shown to be the main source of errors in experiments reported by most of the studies reported in the past (Verma, 1986).

Capillary pressure effects can be reduced either by use of a sufficiently long core or by using a sufficiently high injection rate. Our experience shows that, at injection rates reported by most investigators, the capillary effects are difficult to eliminate completely and the procedure of taking pressure gradients across the whole length of the core will result in underestimating the relative permeability of one of the phases, most often the wetting phase.

The second most common source of error has been in the determination of saturation. Chen (1978) and Council (1979) used a capacitance probe to measure saturations and obtained very low values of steam saturations over a narrow margin of saturation change. Chen et al (1976) did recommend the use of a gamma ray densitometer for more reliable measurements of saturations. Verma (1985) used a gamma ray densitometer to measure saturations. However the probe could measure saturations over only 5% of the core space and could not obtain saturations over the entire core radius. In addition, problems associated with heat generation severely affected some of the measurements. More recently Sanchez (1988) reported the use of average recovery time of a tracer, which was introduced with the fluid to determine the saturation of the liquid phase. This method gives the average saturation of the liquid phase in the entire core and ignores any local variations that are likely to be present in the flowing two-phase single-component systems experiencing a pressure gradient. Since a given change in saturation does not necessarily bring about a proportional change in relative permeability these results may be questioned, particularly towards the end points where relative permeabilities have been shown to have an asymptotic behavior due to rapid drop in mobility as saturation declines.

In the experiments discussed here, these two problems were overcome by using a high resolution X-ray computer tomography (CT) scanner that can measure saturations across a given section of a core to an accuracy of a few percent (Johns et al, 1993). Water pressures were also measured at various locations along the core and the pressure gradient was computed from the interval over which a flat saturation profile exists. Over this interval the pressure gradient is presumed equal in both phases in spite of the capillary forces. With this method, the complications associated with boundary effects can be eliminated using readings from sections with small saturation gradients.

To establish this technique as capable of eliminating the two effects, experiments for nitrogen and water were conducted first, and results are reported here. For the case of steam and water, it was not possible to ensure completely adiabatic conditions because the X-ray CT scanner requires that no metals be within the scanning area which eliminated the use of guard heaters. Instead a highly efficient insulation made of ceramic material was used and proved to be reasonably effective. A number of improvements still have to be applied to completely eradicate the effects of heat losses.

NUMERICAL SIMULATIONS

In order to design an experiment in which the boundary or end effects are minimized, numerical simulations using some of the published relative permeability curves were used. This was done by varying petrophysical parameters and core length, and investigating the effect of injection rates on the zone affected by the capillary end effect. For the steam and water experiments, the numerical simulations were also used to assess how adversely heat losses would change the saturation distribution along the core and how different the thermodynamic conditions would be from those of ideal adiabatic conditions.

Numerical simulation results for the adiabatic steam-water flow experiments were reported by Satik et al (1994). These simulations were one-dimensional and did not consider the effect of gravity. To take into account the effect of gravity and to adequately determine the radial saturation and temperature distribution associated with heat losses, a three dimensional model was used. Figures 1 and 2 show steam

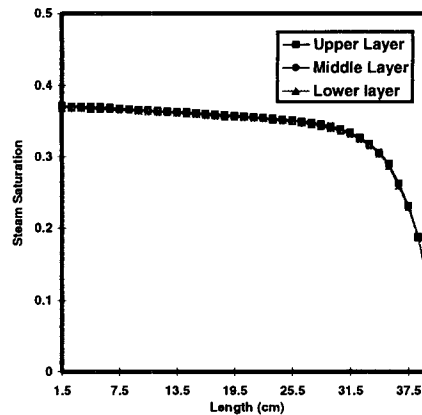


Fig. 1 Steam Saturation along the core on three layers.

saturation and pressure distribution along the upper, middle and bottom layers. In general they show that the saturation distribution in the vertical direction will vary by less than 3% while pressure will be essentially constant in the vertical direction except at the end points where there will be some nonaxial flow.

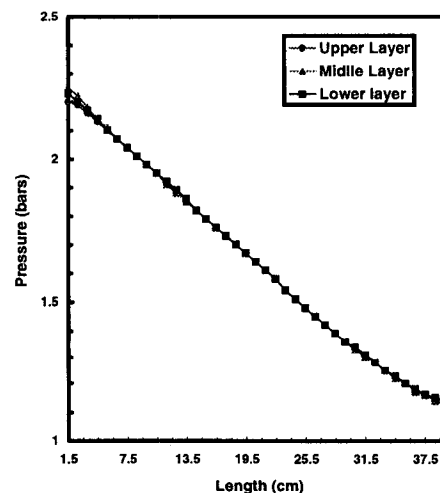


Fig. 2 Pressure along the core on three layers along the core.

Figure 3 shows the average steam saturation distribution for the cases with heat losses and for the adiabatic case, as obtained by Satik et al. (1995). The injection rates and steam quality were the same in both cases (14 g/min, 10% steam by mass). However since the pressure at the core exit was set at the same value in both cases, the injection temperature for the non-adiabatic case was higher than for the adiabatic case. The results show that the saturation distribution

is most affected closer to the production end while the profile does not have the gradual decline seen in the adiabatic case. Also, the pressure and the temperature drop more rapidly in the non-adiabatic case. In general the effect of heat losses are not severe near the injection end of the core where a distinct flat saturation develops. Results obtained from this section corrected for heat losses can be used to infer relative permeability.

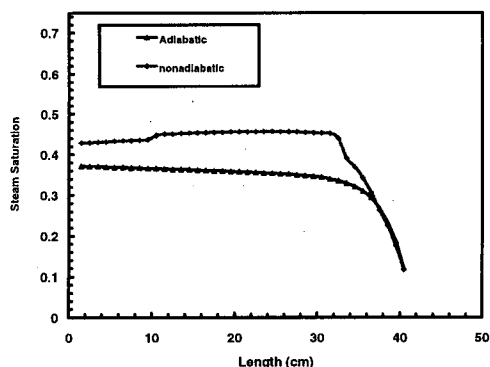


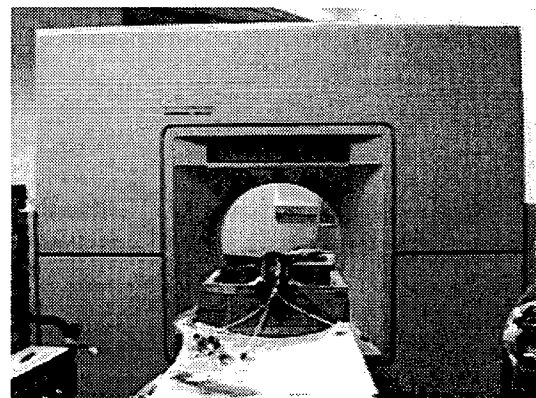
Fig. 3 Saturation distribution for adiabatic and non-adiabatic case.

EXPERIMENTS

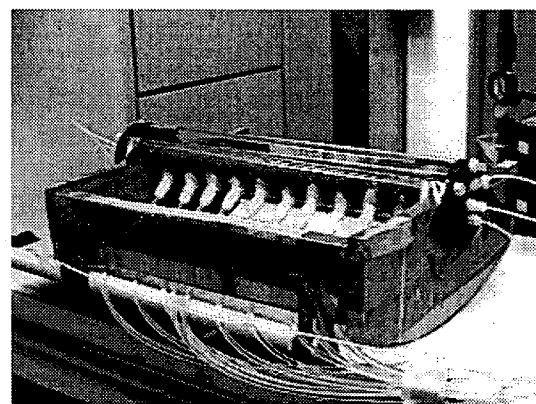
The description of the apparatus for these experiments was discussed by Satik et al (1995). In general, it consists of an injection unit, a core holder and a condensing unit for the steam and water experiments. For the nitrogen and water experiments the injection unit has two lines: one for nitrogen and another for water. The two fluids were mixed before entering the core. The two phases were then separated after leaving the production end and the nitrogen and water flow rates were checked for the accuracy.

For the steam and water flow experiments, the two injection lines for nitrogen and water were replaced by those for saturated water and steam. On each line was a steam generator through which water was pumped continuously with the use of two low-pulsation reciprocating pumps. By using temperature controllers on the steam generators it was possible to vary the heat flow to achieve the required temperature and by means of throttle valves on the lines it was possible to ensure that either saturated water is generated at temperatures close to saturation for measured pressure or superheated steam at temperature above that for saturation pressure. The two streams of fluid were then mixed to obtain the desired steam quality at the core inlet.

The core (rock) sample used for these experiments have been described in detail by Satik et al. (1995) and had the following properties; permeability 600md, porosity 20%, length of 38 cm and radius 5.04 cm. The core sample was first heated to 400°C for twelve hours to deactivate clays and to get rid of residual water. The two ends of the core were then covered by the end plugs fitted with nipples for injection and production of fluid. Twelve ports to measure temperatures and pressures were then fitted at the fixed intervals along the edge of the core before the rest of the core was covered completely by high temperature epoxy. The core was tested for leaks before being covered with an insulation material, made of ceramic blanket. The core was placed on a motorized bench that could be moved to precise locations and scanned as required. A picture of the experimental apparatus within the X-ray CT scanner is shown in Figure 4.



(a)



(b)

Fig. 4 Pictures of (a) X-ray CT scanner and (b) the core holder used in the nitrogen-water flow experiments

Prior to starting the experiment, the porosity of the sample was determined by comparing the X-ray scans of the completely dry sample to those taken when the sample was fully saturated with water. Figure 5 shows the porosity distribution obtained from a reconstruction of the porosity measurements done at 1 cm intervals starting at the core inlet.

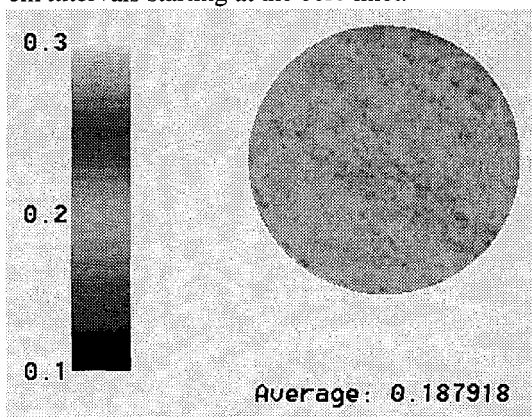


Fig.5 Porosity distribution obtained from the X-ray CT scanning, at a cross-section of a Berea sandstone core.

The absolute permeability was also determined by injecting water through the core at constant rate. For nitrogen-water the experiments were conducted in stages of increasing fraction of nitrogen from an initial pure water flow and thereby furnished a drainage relative permeability curve. For each given fraction, the flow rate was maintained for about five hours before measurements were taken. This was typically ten times longer than the stability time predicted by the numerical simulations. The fraction of nitrogen was then increased and progressively the relative permeability curve shown on Figure 6 was generated.

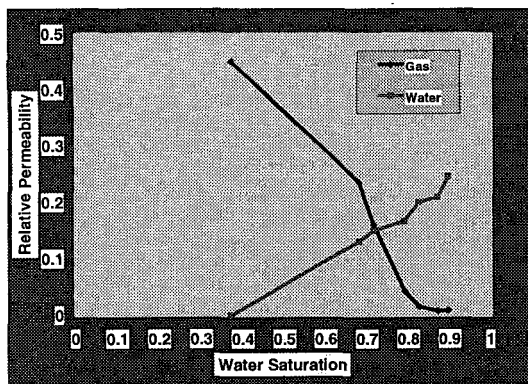


Fig. 6 Relative Permeability Curves for Nitrogen-water.

However, there was some difficulty in lowering the water saturation, probably due to a rapid decline in wetting phase relative permeability as the residual saturations are approached. Nonetheless the curves show good agreement with those established from other published experiments and give credibility to this method.

Figure 7 shows the gas saturation distribution at a location along the core, obtained from the X-ray data taken during the experiment. The figure shows a uniform distribution of gas over the cross sections.

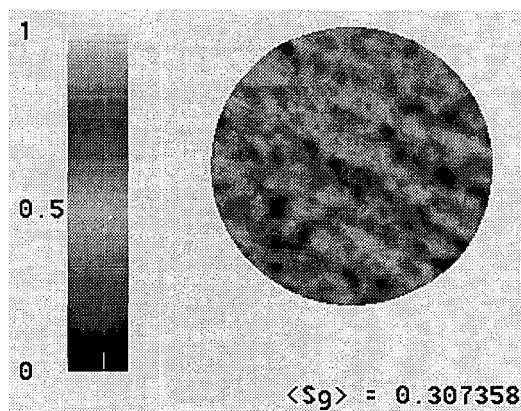


Fig.7 Gas saturation distribution, obtained during a nitrogen-water flow experiment, at a cross-section of a Berea sandstone core.

For the steam-water experiments the core was preheated to the experiment temperature by injecting hot water. This was done in stages and thermal equilibrium was first established before the temperature was increased again to a new temperature. Once the desired temperature for the experiment had been attained the required ratio of steam to water was obtained by adjusting the settings on the steam generators and varying the throttling of the valves to ensure that either water at saturated conditions or slightly superheated steam was generated. In this case the equilibrium was ensured when constant temperature was recorded along the core which was about three hours.

Figure 8 shows saturation profiles along the core for flow rates of 6 and 3 gm/min of water with steam fractions (mass) of 4% and 16% respectively. The anomalously low steam saturation measured at about 12 cm from the injection end the injection end of the core was established to be due to steam channeling at the lower part of the core, presumably caused by a separation between the epoxy and the core. An end effect as indicated by the rapid decline in steam at the

end of core from about 33 cm to the end of the core (44 cm) was also seen. Figure 9 shows the steam saturation at a selected cross-section along the core.

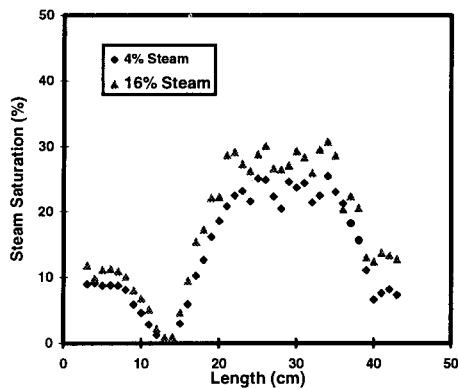


Fig. 8 Steam saturation along the core.

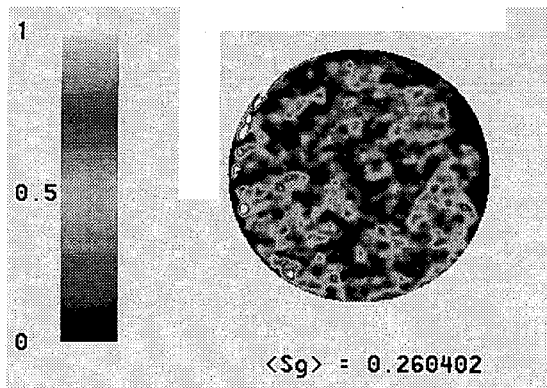


Fig. 9 Steam saturation distribution, obtained during a steam-water flow experiment, at a cross-section of a Berea sandstone core.

As a result of the steam channeling, the flat steam saturation profile between 21 cm and 33 cm was unusable for evaluating values of the relative permeability since the flow should be entirely axial. Furthermore, in order to estimate flow rates for steam and water it is required that the enthalpy of the fluid at each section be known and this implies that some estimate for the heat losses must be made. These two factors will be addressed in future experiments.

Using the X-ray CT scanner to measure gas and steam saturation and the measurement of pressure along the core has been shown by the experiments discussed above to have overcome the main problems associated with accurate determination of relative permeability. However improving the construction of the core holder to avoid steam channeling still remains as a crucial step in obtaining error-free relative permeability curves for steam and water.

Steam channeling by comparatively smaller channels as in consolidated sand packs has been known to increase the permeability of the gaseous phase thereby leading to overestimates of the gas phase permeability (Verma, 1986). Overcoming this problem should extend the length of the flat saturation profile closer to the injection end of the core and improve the accuracy of the results. It will also be important to establish flowing fractions over intervals for which the relative permeabilities are being calculated by measuring the heat losses during the experiments by using heat flux sensors. Alternative methods of conducting experiments in constant temperature baths will also be considered.

Since the primary objective of these experiments is to determine steam-water relative permeability curves and understand the role of phase change by comparing the results to the results for nitrogen and water it is important that effects of temperature particularly on rock properties such as porosity that may change with temperature be accounted for. This we intend to achieve by conducting permeability measurements at various temperatures during the heating stages of the experiment.

CONCLUSION

An accurate method for measuring relative permeability relations for simultaneous flow of gas and liquid in porous medium has been developed and tested by application to the flow of nitrogen and water. The curves obtained from these experiments are similar to those obtained by other investigators using other methods. In the next phase of the project, this method of determining the relative permeability relations will be used to measure similar curves for flows of steam and water.

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