DOE/BC/14897--12

TITLE: ANISOTROPY AND SPATIAL VARIATION OF RELATIVE PERMEABILITY AND LITHOLOGIC CHARACTER OF TENSLEEP SANDSTONE RESERVOIRS IN THE BIGHORN AND WIND RIVER BASINS, WYOMING

D.O.E. Contract No. DE-AC22-93BC14897

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Date of Report: April 26, 1996
Award Date: September 15, 1993
Completion Date: September 14, 1996

Government Award for Current Fiscal Year: $239,353

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Reporting Period: January 1, 1996 - March 31, 1996

Objectives

This multidisciplinary study is designed to provide improvements in advanced reservoir characterization techniques. This goal is to be accomplished through:

1. an examination of the spatial variation and anisotropy of relative permeability in the Tensleep Sandstone reservoirs of Wyoming;
2. the placement of that variation and anisotropy into paleogeographic, depositional, and diagenetic frameworks;
3. the development of pore-system imagery techniques for the calculation of relative permeability;
4. reservoir simulations testing the impact of relative permeability anisotropy and spatial variation on Tensleep Sandstone reservoir enhanced oil recovery; and
5. a geochemical investigation of the spatial and dynamic alteration in sandstone reservoirs that is caused by rock-fluid interaction during CO_2-enhanced oil recovery processes.

Summary of Technical Progress

Regional Frameworks

Work in conjunction with Marathon Oil Company in the Oregon Basin field utilizing Formation MicroImager and Formation MicroScanner logs has been completed. Tensleep outcrops on the western side of the Bighorn Basin are not of the quality necessary to do detailed study of stratification. This made the use of borehole imaging logs, in which stratification can be recognized, particularly attractive for the western side of the Bighorn Basin. The borehole imaging logs were used to determine the dip angle and dip direction of stratification as well as to distinguish different lithologies. It is also possible to recognize erosional bounding surfaces and classify them according to a process-oriented hierarchy. Foreset and bounding surface orientation data was utilized to create bedform reconstructions in order to simulate the distribution of flow-units bounded by erosional surfaces. The bedform reconstructions indicate that the bedforms on the western side of the basin are somewhat different from those on the eastern side of the Bighorn Basin. A report has been submitted to Marathon Oil Company, the principal cost-share subcontractor.

Marine dolomitic units initially identified and correlated in the Bighorn Basin have been correlated into the Wind River Basin. Gross and net sand maps have been produced for the entire upper Tensleep in the Bighorn and Wind River Basins, as well as for each of the eolian units identified in the study. These maps indicate an overall thickening of the Tensleep to the west and south. This thickening is a result of both greater subsidence to the west and south and greater differential erosion to the north and east.

An article documenting the North Oregon Basin field study will appear in the Gulf Coast Society of Economic Paleontologists and Mineralogists Foundation Conference volume entitled "Stratigraphic Analysis Utilizing Advanced Geophysical, Wireline and Borehole Technology for Petroleum Exploration and Production".

Relative Permeability Derived from Image Analysis

A process has now been developed by which petrographic image analysis can be related to relative permeability. It also produces the ability to predict relative permeability from petrographic variables through theoretical and empirical algorithms. These equations will then be used to evaluate the role of distinct sedimentologic features with respect to anisotropy encountered in the Tensleep. The algorithms will also be used to construct a detailed map of the variations in relative permeability through an eolian sequence. The results will then be placed into a geologic and spatial context to further define trends in relative permeability with respect to sedimentologic features and to the spatial orientation of these features in an eolian sand package. By placing these features into a reservoir context, better production strategies can be developed for the Tensleep. The development of these algorithms will provide operators with the ability to cheaply construct detailed maps of relative permeability variation, on any scale, for any reservoir in the Tensleep.

The relative permeability measurements on core plugs collected during the second field season were completed this quarter. A total of 26 samples have been measured for relative permeability, bringing the total number of samples measured during the study to 60. Thin section billet impregnation and grinding have been completed for all of the samples to be used in the image analysis portion of the study following the guidelines described by Pittman[1] and outlined in the second annual report. Billets that were cut from the core plugs collected during this study have been made into thin sections. A total of 100 thin sections have been made for the image analysis portion of the study. These include samples that have been measured for relative permeability and samples that will only be subjected to image analysis. Relative permeability will be calculated for these samples using the algorithm described below. Fifty-four of the thin sections have relative permeability measurements. A subset of these samples will be used to test the relative permeability algorithms, while relative permeability of the remaining 46 thin sections will be defined only through the use of the relative permeability algorithms. These samples will be used to further define trends in relative permeability in the Tensleep sandstone.

An algorithm has been developed for predicting oil relative permeability curves from distinct and measurable pore-network variables. From saturation data predicted using this initial algorithm, another algorithm has been developed that accurately predicts the relative permeability curve of water. These algorithms can be applied to quickly and cheaply predict the relative permeability curves of both water and oil from data derived from the pore structure. The calculated data can then be placed in a sedimentologic and geometric framework to better understand how relative permeability varies with respect to sedimentologic features. The algorithm for the oil relative permeability curve is based on the work of Mowers[2], Ehrlich[3], and Ruzyla[4]. Portions of these previous studies can be combined into a single equation that is based on the Carman-Kozeny equation. This equation can then be modified and used for the prediction of relative permeability. The equation used for the prediction of water relative permeability is based on work by Honarpour *et al.*[5] and Honarpour[6], and is an empirically derived equation that uses predicted water saturations to determine the relative permeability of water for that sample. Figure 1 shows an example of preliminarily results from these equations. More testing of these algorithms must be completed, but results to date clearly show that it is possible to predict relative permeability from quantitative analysis of the pore structure using petrographic image analysis techniques.

The developed algorithms will now be further tested using the defined image analysis techniques. Any revisions to these original equations will be made as shown to be needed by more tests. The final developed algorithms will then be used to predict both water and oil relative permeability curves for the remaining samples. The results can then be placed into a geologic context, and the role of each sedimentologic feature in regard to relative permeability anisotropy can be evaluated.

CO_2 Flood -- Formation Alteration and Wellbore Damage

The work of this task is to establish criteria for the susceptibility of Tensleep reservoirs to formation alteration resulting in a change in absolute or relative permeability and possible wellbore scale damage during CO_2 enhanced oil recovery. This advanced reservoir characterization technology will be used to optimize recovery efficiency. This task includes:

1. flow experiments on core material to examine the effects of CO_2 flooding on the alteration of the fluid and rock system;
2. examination of regional trends in water chemistry;
3. examination of local water chemistry trends at field scale; and
4. chemical modeling of both the reservoir and experimental systems in order to scale-up the experiments to reservoir conditions.

During this quarter, chemical analyses of sample solutions of the fourth CO_2 core flooding experiment, which was run in December 1995, have been completed. Results showed that much anhydrite cement dissolved into solution at the early stage of the run, because the nutrient solution (0.25 mol/l NaCl solution) was highly undersaturated with respect to the mineral. Concentrations of Ca and SO_4, however, decreased with reaction time, and Ba concentration increased, so that the solution was saturated with respect to barite throughout the run. These results are in contrast to those of previous runs, in which the nutrient solution originally saturated with respect to anhydrite was used. Dolomite dissolved into solution at a relatively constant rate (average alkalinity was about 16 mmol/l), whereas the solution remained undersaturated with respect to dolomite.

The fifth CO_2 core-flooding experiment was carried out during this quarter at the Petroleum Technology Center, Marathon Oil Company, Littleton, Colo. Temperature and pressure conditions were similar to those in prior runs [80°C and 166 bars ($P_{CO2} = P_{total}$)]. In this experiment, Tensleep oil from the Oregon Basin oil field was used as well as subsurface cores from the Oregon Basin oil field and synthetic 0.25 mol/l NaCl solution. Prior to the experiment, three cores were saturated with brine and then some aliquot of brine was replaced by oil. The initial water saturation of the three cores was 28, 28, and 34%. The brine, which was saturated with CO_2 gas at run conditions, was injected into the core assemblage, so that oil as well as brine came out of cores with time. Thus, this experiment simulated a CO_2 flood in a more realistic manner than in previous runs. The total run duration was 143 hrs.

Work in the next quarter will include chemical analyses of sample solutions and cores of the fifth run and chemical modeling of sample solutions. Those data will be synthesized with those obtained through all of previous core flooding experiments as well as data on Tensleep formation-water chemistry to establish the susceptibility of the Tensleep formation to formation alteration and wellbore damage due to CO_2 treatment.

Technical Transfer

Our website for project results and updates now contains the first and second annual reports as well as these two recently accepted abstracts. Our website may be accessed at http://garfield.uwyo.edu/doe/tensleep.html. In the future this site will contain additional detailed information, data, and updates on conclusions reached.

References

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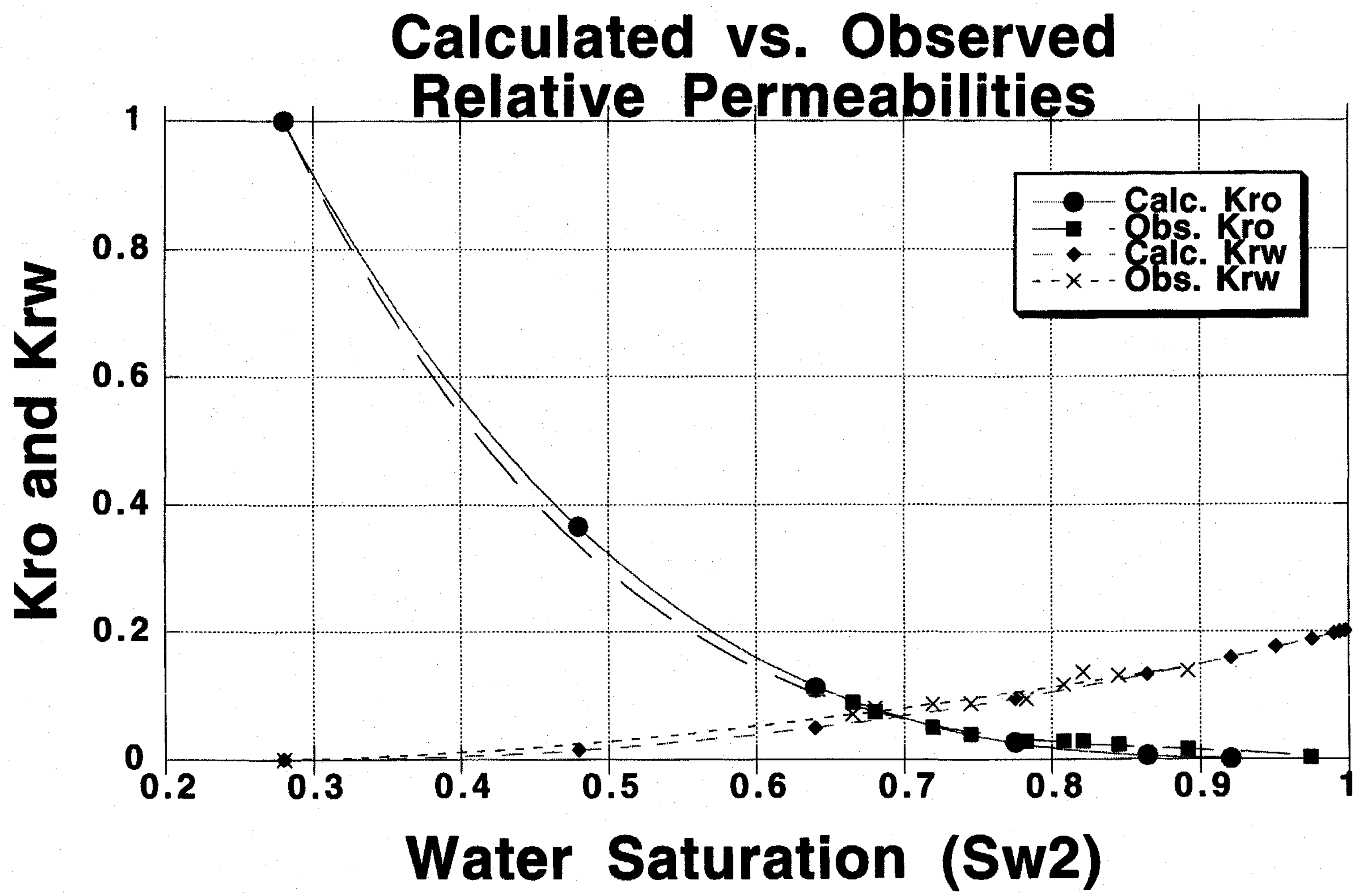

Fig. 1 Predicted and observed relative permeabilities vs. water saturation (Sw2) for both oil (Kro) and water (Krw). Data is from the Wilson B12 3286'v sample from the Oregon Basin Field.